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Application of the DPU's Used-and-Useful Standard to Pilgrim 1

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1 Introduction and Summary

This study assesses the rate-making treatment which would result from the application of the precedents of the Massachusetts Department of Public Utilities (DPU) to the cost recovery of Boston Edison (BECO) for the retail share of its Pilgrim nuclear power plant.[1]

We approached this question in the context of the DPU's "used-and-useful" rule, which the Department applied to the share of Millstone 3 owned by Western Massachusetts Electric Company (WMECO). This rule, and its significance for operating baseload plants, are discussed in Section 2 of this report.

Our detailed analysis of the useful portion of BECO's investment in Pilgrim is presented in Section 3 of this report. For most plausible assumptions about the future, our comparison of Pilgrim's costs to the costs of replacement power indicates that 30% or more of Pilgrim investment at the end of 1987 (about $220 million) will not be economically useful. It is also likely that most of the remaining year-end investment will not be economically useful. In fact, bringing Pilgrim back into service and operating it is likely to be more expensive for ratepayers

1. Pilgrim is often referred to as "Pilgrim 1," to distinguish this unit from a second unit planned for the generating station in the 1970s, called Pilgrim 2. (BECO also had a short-lived plan to build a third Pilgrim nuclear unit, but this unit was never ordered.) The second unit was canceled in 1981, after over $400 million had been invested in it. Since there is now only one Pilgrim unit, we will not bother with the Pilgrim 1 title.

than replacing Pilgrim with conservation, small power, and increased use of existing oil plants, unless one or more of the following occurs:[2]

1. Pilgrim operates much more reliably than it has in the past, the cost of operating Pilgrim (which has been rising much faster than inflation) stabilizes soon, and required additions to Pilgrim stabilize or fall; or

2. oil prices rise to a level far above the current projections, and BECO is unable to find other non-oil alternatives to Pilgrim.

Section 4 of this report describes the historical cost and operating experience of Pilgrim and similar plants, and derives projections for the significant determinants of Pilgrim's future cost of power. For most input factors, we provide Historic estimates which are based on Pilgrim's past experience, or other projections Unfavorable to Pilgrim; projections which are very Optimistic or Favorable to Pilgrim; and estimates which are

2. These analyses are based on BECO costs. BECO sells 11% of Pilgrim output to each of two investor-owned utilities, Montaup (part of Eastern Utilities Associates and wholesale supplier to Eastern Edison) and Commonwealth Electric, and about 3% more to various municipals. Pilgrim costs are essentially the same for all participants, except that BECO's sales to the other utilities are regulated by the Federal Energy Regulatory Commission (FERC), which generally allows higher rates than does the DPU. Montaup and Commonwealth project replacement power costs are lower than BECO's (see Appendix 3), so Pilgrim would be even less cost-effective for these utilities than for BECO. We have not analyzed the situation for the municipals, but their low financing costs should make replacement power even less expensive.

Intermediate in nature, generally requiring Improved experience compared to past results.

Section 5 discusses the potential range of BECO power supply situations, over the next 25 years, including the need for capacity, the source of replacement energy for Pilgrim, and the cost of replacement energy.

The last two sections of this report consider the likelihood that the current outage at Pilgrim will represent the end of its major problems. Section 6 examines the history of other nuclear plants which have experienced major regulatory outages, to determine whether such outages appear to be turning points in the recovery of troubled plants. Section 7 examines the possibility that the current outage will resolve all the remaining identifiable safety issues, whether specific to Pilgrim, generic to plants of its design, or generic for all nuclear power plants. If additional issues remain to be resolved, they may result in further major outages, poor reliability, high backfitting costs, high operating costs, and a short remaining life.

2 Application of the DPU's Used-And-Useful Rule to Existing Plants

In evaluating the continued cost-effectiveness of Pilgrim upon its return (if it does return) to service from its current extended outage, the DPU would apply its used-and useful test first enunciated in Re Western Massachusetts Electric Company, D.P.U. 84-25, pp. 27-43 (July 31, 1984) and first applied in Re Western Massachusetts Electric Company, D.P.U. 85-270, pp. 60-107, 119-132A (June 30, 1986).

Some historical context may help explain the DPU's abandonment of the traditional "prudent investment" rule, which held the costs of any investment, as long as they are prudently incurred at the time the investment decision was made, would be placed in rate base, no matter how poorly the investment performed on an after-the-fact basis. Several factors argued against the continued unthinking application of the old "prudent investment" rule in the 1980s. First, the huge cost of some nuclear power plants would have pushed electric rates to unacceptable levels, and would have caused substantial sales erosion and earnings erosion, if they were placed in rate base in full immediately after entering commercial service. Second, after-the-fact "prudency reviews" are enormously difficult and controversial undertakings, and require very substantial regulatory resources to be accurate and fair. Third, the general pressures to attempt to deregulate electric power generation (at least on the margin) lead to the

general replacement of old "cost of service" doctrines with "value of service" doctrines.

The DPU's used and useful test compares the Cumulative Net Present Value of the Revenue Requirements (CNPVRR) of the generating unit in question to the CNPVRR of the supply alternatives which would be utilized in place of the generating unit in question. If the former exceeds the latter, the ratio of the latter to the former provides the ratio of the generating unit's cost which is determined to be used and useful. Furthermore, when evaluating the CNPVRR of the generating unit in question, the future revenue requirements caused by sunk costs (such as return on investment, and depreciation expense) are included in the analysis.

An example of the DPU's application of the used-and-useful test will help make this clear. After Millstone 3 went into service, the DPU reviewed Millstone 3's economics in the next WMECO rate case, DPU 85-270. The DPU first made a finding that all of the Millstone 3 investment was prudently made (pp. 32-35, 38-59). The DPU next found that Millstone 3 was "used," noting that it was in commercial operation, that it provided some benefits to WMECO's ratepayers, that it had achieved 100% power, that it had completed its 100-hour warranty run, and that it had been turned over to NEPEX for economic dispatch purposes. Re Western Massachusetts Electric Company, DPU 85-270, pp. 60-63 (June 30, 1986). With respect to whether or not Millstone 3 was "useful," the Department first decided to apply a CNPVRR test, comparing the CNPVRR of the WMECO system with Millstone 3 to the same

system without Millstone 3; the DPU rejected three alternative tests (the replacement energy cost method, the avoided cost method, and the market-clearing price method). Re Western Massachusetts Electric Company, DPU 85-270, pp. 71-75 (June 30, 1986). The Department next set out what it considered to be the relevant input variables to the two cases (pp. 76-102). The Department then calculated the CNPVRR of the Millstone 3 case as $627 million; the CNPVRR of the supply alternatives case (gas turbines and combined cycle plants) as $479 million, or $148 million less than the CNPVRR of the Millstone 3 case. As the Millstone 3 case was more expensive than the supply alternatives case, the DPU found that 76% of Millstone 3's capital cost was useful, and 24% was not useful, under the "used-and-useful" test (pp. 102-104). (The 24% was the ratio of the $148 million "excess cost" to the $627 million total cost described above). The Department accordingly found 76% of Millstone 3's capital cost to be used-and-useful, and placed 76% of its cost in rate base (phased in over 5 years). The Department excluded the other 24% from rate base, amortized it over a 10 year period, and also disallowed the equity portion of AFUDC, and any return on the unamortized portion, from the 24% amount (pp. 108-132).

Thus, for Pilgrim, the Department would compare the CNPVRR for Pilgrim (which would include nuclear fuel, non-fuel O&M, depreciation expense, decommissioning provisions, insurance, local property tax, and return on the undepreciated contribution to rate base, grossed up for taxes) to the CNPVRR for the alternatives to Pilgrim. The alternatives to Pilgrim would be

some combination of wholesale purchases and increased oil-fired generation at New Boston and Mystic (in the short run), gradually replaced by conservation and load management (C&LM), small power production, cogeneration and possibly combined-cycle or coal plants (in the long run). The only costs related to Pilgrim which would be excluded from this analysis would be expenses already collected in rates, such as accumulated depreciation, decommissioning expense provisions, and return on contribution to rate base already collected.

It should be noted that any potential modifications being considered by the Department to its used-and-useful standard for future plant (see Re New Generating Facilities, D.P.U. 86-36-A, pp. 55-87 (April 7, 1987)) would not be applicable to Pilgrim, just as they were not applicable to Millstone 3. Any such modifications would only apply (if at all) to plant started after the date of the first Western Massachusetts case, i.e. after July 31, 1984.

In the New Generating Facilities case, it appears that the DPU may be reconsidering the "used-and-useful" test, and may be thinking of replacing it with a hybrid test, called the "prudent, used-and-useful" test. This test excludes all imprudently-made investments from cost recovery, permits the "used-and-useful" portion of prudently-incurred costs to be recovered by being placed in rate base, and splits the "not-used-and-useful" portion of prudently-incurred costs between the ratepayer and the stockholder by amortizing them, without a return being earned on

the unamortized portion, and with the equity portion of AFUDC being excluded from the amount amortized.

3 Useful Portion of Pilgrim

This section describes the derivation of our estimates of the portion of Pilgrim investment which is economically useful under the DPU's used-and-useful rules discussed above. The first step in this process is the identification of the categories of costs and other parameters[3] which will be included in the analysis.

3.1 Costs and Other Parameters Included in the Analysis

The current analysis uses one or more levels of each of the following parameters:

1. **Recovery of Sunk Costs:** This category includes the depreciation, rate of return, and income taxes on the plant investment as of the present time, which we took to be December 31, 1987. These charges simply repay BECO for the funds it has already put into plant. Our analysis of sunk cost recovery is based closely on a calculation provided by BECO (see Appendix 1).

3. By "parameters," we mean any of the numbers which contribute to making a plant cost-effective. Most of these parameters are costs, such as construction costs, operating costs, decommissioning costs, and so on, but other important parameters determine how much benefit is derived from the plant. Examples of this category include the plant's rated capacity, its capacity factor, and its useful life.

2. **Capital Additions:** The total cost of almost any power plant rises over time, as additional investments are required to keep it operating efficiently. In the case of nuclear plants, and especially Pilgrim, the "capital additions" have been considerable. BECO's total investment in Pilgrim was $239 million at the end of 1973, but it had grown to $696 million at the end of 1986.

3. **Non-fuel Operating and Maintenance Expenses:** These are the direct costs of running the plant, such as salaries for plant operators, outside services, and the costs of routine replacement materials (e.g., filters and lubricants). The O&M costs are reported by the operators of each US nuclear power plant to the FERC, and are distinct from the capital additions.

4. **Fuel:** This is broken out of the other O&M costs for two reasons. First, nuclear fuel costs have been quite steady in recent years, while the other O&M costs have been rising rapidly, suggesting that different projection techniques may be appropriate for the two costs. Second, fuel costs vary with the level of plant output, while the other O&M costs increase little (if at all) as plant operation increases.

5. **Rated Capacity:** As for most products, the capacities of nuclear power plants are rated in different ways for different purposes, complicating comparisons between plants. Pilgrim has in the past been accredited by NEPOOL

as having a net capacity (that is, in addition to the power used in the plant itself) of 670 MW. We use this figure wherever possible, but we must sometimes convert data from capacities stated in different terms. BECO has sold off 25% of the plant's capacity in life-of-unit contracts, leaving it with an entitlement of 498 MW.

6. **Capacity Factor:** The capacity factor of a power plant is the plant's actual output (in megawatthours) in some time period, divided by its total potential output (the rated capacity times the number in that period). Pilgrim's capacity factor is very important in determining its value in displacing BECO's oil-fired generation and purchases from other utilities. The higher the capacity factor, the more economical Pilgrim will be.

7. **Useful Life:** The longer Pilgrim remains in operation following its current outage, the more economical it will be. If Pilgrim is retired after only a few years of further operation, there will be fewer years to recover the costs sunk through 1986, the capital additions from this outage and future additions, and the costs of decommissioning. Pilgrim would also be available (if at all) only in the period when oil prices are expected to be low, and would not be in operation when its energy production would be most valuable.

8. **Decommissioning Expense:** After Pilgrim is retired (whether that is in 1987 or in 2008), BECO will have to pay

the costs of decontaminating and disassembling the plant. Those costs are currently being collected from ratepayers, so that the collections plus interest will equal the expected cost of decommissioning in 2008. The higher the final cost of decommissioning, and the shorter the operating life of Pilgrim, the higher the required contribution in each year.

9. **Property Tax:** The property taxes BECO pays to Plymouth are largely determined by the net depreciated cost of the plant.

10. **Overheads:** In addition to the O&M costs reported as station O&M, utilities have expenses related to the ownership of nuclear plants which are not usually assigned to the plant accounts. These expenses include employee benefits (such as pensions), employment taxes, insurance, legal fees, and regulatory expenses. We have estimated these costs (as a fraction of station O&M) from the FERC reports of the Yankee companies (which have no non-nuclear operations), and applied that percentage to Pilgrim.

11. **Replacement energy costs:** If Pilgrim does not operate, its energy production must be replaced by additional operation of BECO's oil-fired plants, purchases of power from other utilities or independent producers, or a conservation program. We have used replacement power projections based on BECO's estimates for its small power producer rate filing, and an alternative estimate based on

the cost of operating the New Boston oil-fired plant. Which of these projections turns out to be more realistic will depend on the scope of BECO's conservation programs and of its purchases from small power producers. We have run our projection for low, medium, and high oil prices from DRI (BECO's preferred source for oil-price projections).

12. **Replacement capacity costs:** In addition to replacing Pilgrim's energy kWh's produced at any time, BECO may also have to acquire additional capacity (the ability to serve kilowatts of instantaneous load) to meet its obligations to NEPOOL. We estimated BECO's capacity needs under its load forecast, and with various levels of additional conservation investment. We have used BECO's assumptions regarding the cost of replacement capacity.

13. **Discount rates:** In order to compare costs over time, it is necessary to discount the value of later costs, to reflect the fact that a dollar now is worth more than a dollar in 5 or 10 years. We use the traditional utility approach of discounting at BECO's cost of capital, and also use higher discount rates to reflect consumer preferences.

3.2 Sources of the Parameter Values

We have determined the used-and-useful portion of Pilgrim investment to date, under various combinations of assumptions. For most cost inputs, we defined three values:

- Historic values, which reflect the prior experience of Pilgrim, where available, or of the industry,
- Optimistic values, which assume that Pilgrim's performance rises to some of the best experience in the industry, and
- Improved values, which assume that Pilgrim will show results which are better than indicated by the historical record, but not as good as the best possible performance.

For replacement cost inputs, we calculated values which were Favorable to Pilgrim, Unfavorable to Pilgrim, and Intermediate values.

The Optimistic inputs for the most important cost parameters (capacity factor, O&M, and capital additions) are based on the experience of Vermont Yankee. We use Vermont Yankee as a model for this purpose because (1) it is a quite successful nuclear plant similar to Pilgrim in design and size, and (2) it has been suggested that the Yankee Atomic organization[4] may eventually

4. Even though Yankee Atomic does not operate any of the Yankee plants other than Yankee Rowe, it is often given credit for

assume responsibility for operation of Pilgrim. Where no Vermont Yankee experience is available, as for decommissioning and remaining plant life, the Optimistic projections are based on BECO projections.

Historic inputs are generally based on Pilgrim's own historical experience. Where no Pilgrim data is available, as for decommissioning costs or for operating lifetime, we based the Historic projection on industry-wide data, or other independent data. It is significant that the Historic cases generally do not represent a deterioration from historical experience: the Historic assumptions are far from worst-case scenarios. In general, the continuation of Historic conditions would ensure none of the existing Pilgrim investment would be used-and-useful, and would make the restart of Pilgrim highly uneconomic. Hence, it was unnecessary to examine the possibility of future results which are worse than past results, although this possibility certainly exists. The projections which deviate from historical results will all assume some improvement at Pilgrim.

The Improved projections are either taken from industry experience (where this is significantly better than the Pilgrim data), or are simply averages of the corresponding Optimistic and Historic projections. The national experience used in these calculations generally includes all U.S. nuclear plants, adjusted for size, location, and similar characteristics. For capacity

the superior performance of the other plants: since Yankee provides consulting services to the Vermont and Maine plants, this explanation is plausible.

factors, the national experience is drawn from boiling water reactors (BWRs), the technology which includes Pilgrim.

For the Favorable (high) replacement power cost, we used DRI's high oil price projection and BECO's load forecast. For the Unfavorable replacement power cost cases, we used the DRI low oil price projection and BECO's load forecast, adjusted for a conservation program comparable to that suggested by the recent Review Panel report. Intermediate replacement power costs are based on DRI Reference oil prices and a conservation program only half as aggressive as that of the Review Panel.

All analyses of historical data are conducted in constant dollars, to eliminate the effects of past inflation. Costs are projected into the future at the inflation rates projected by BECO. All costs are computed for the entire Pilgrim plant, and a 75% share of the totals are allocated to BECO. The benefits are calculated directly for the BECO share of the plant.

This section will include a run representing a best case for justifying continued operation of Pilgrim (all inputs Optimistic or Favorable), a run assuming no improvements and low oil prices (all Historic and Unfavorable inputs), a run with all inputs at their Intermediate or Improved values, and other runs varying the most sensitive factors. Finally, we present a "Base Case" analysis, which reflects our best estimate of the cost-effectiveness of Pilgrim: this case includes Historic costs (with 32 year useful life), Favorable load levels, and intermediate oil prices.

The sources of each of the parameters are as follows:

1. Capacity Factors

 - Optimistic: Vermont Yankee mature capacity factor, from its fifth year (starting January 1978) to October 1986 (the most recent data available from the NRC).

 - Improved: The projection for a unit of Pilgrim size and age, from a regression on national BWR capacity factors through 1984, plus additional improvement from the industry-wide decline in post-79 capacity factors.

 - Historic: Pilgrim mature capacity factor, from January 1978 to October 1986.

2. O&M

 - Optimistic: Continuation of Vermont Yankee historical straight-line trend, scaled up for the difference in the units' sizes.

 - Improved: Average of Optimistic and Historic.

 - Historic: Continuation of Pilgrim historical straight-line trend. National regression trends are very close to the Pilgrim data.

3. Capital Additions

- Optimistic: Average Vermont Yankee additions 1980-85, in $/kW.

- Improved: Regression results based on national data, evaluated for Pilgrim characteristics, and 1980s conditions.

- Historic: Pilgrim average 1980-1986.

4. Decommissioning Costs

- Optimistic: BECO assumptions.

- Improved: Average of Optimistic and Historic.

- Historic: BECO assumptions doubled for shorter useful life and doubled again for higher cost of decommissioning (both based on historical industry data).

5. Useful Plant Life

- Optimistic: BECO assumption of retirement in 2008 (36 year useful life, 21 years left).

- Improved: Average of Optimistic and Historic (retirement in 2004, 32 year useful life, 17 years left).

- Historic: Median life of early 1960s units (25 years, retirement in 1997, 10 years remaining).

6. Overheads

- All cases: Assume that ratio of overheads to station O&M is the same for Pilgrim as the average of the four Yankee plants in 1984-85.

7. Oil Prices

- Favorable: DRI high winter 1986/87 oil prices.
- Intermediate: DRI reference winter 1986/87 oil prices.
- Unfavorable: DRI low winter 1986/87 oil prices.

8. Replacement Energy Source

- Favorable: BECO avoided cost from its RFP for small power and cogeneration.
- Intermediate: Average of Favorable and Unfavorable.
- Unfavorable: New Boston is replacement energy source.

9. Discount rates

- Favorable: BECO after-tax cost of capital, 10.34%.
- Intermediate: 15%.

- Unfavorable: 20%.

After the Optimistic, Improved, and Historic parameter values were derived, BECO provided its current projection of Pilgrim costs. This projection included:

1. Capacity factor of 70%, slightly higher than our Optimistic case.

2. Capital additions averaging $50 million/year for 1988-1990, and $40 million/year in 1991 dollars for 1991-2007, falling 24% annually for 2008-2012.

3. O&M starting at $99 million in 1988, rising at an average rate of 3% above inflation to 1991, and remaining constant (in real terms) thereafter. This forecast starts slightly higher than our Historic projection, but falls below the Historic projection in 1993 and below the Optimistic projection in 1996.

4. A useful life of 40 years, through 2012, longer than our Optimistic case.

5. Decommissioning charges of $4.2 million/year, lower than the Optimistic case. The lower annual decommissioning charges are due to the longer useful life assumed.

6. Overhead costs (counting only insurance) of $4.5 million in 1988, rising at the rate of inflation: this is much smaller than our projection of 27% of station O&M, even using BECO's O&M projections.

We used these BECO projections in certain of the cost-effectiveness runs.

3.3 Estimates of the Useful Portion of Pilgrim Investment

In order to determine whether the entire investment in a power plant is economically useful, in the sense the DPU has used that term, we must compare the cumulative net present value of the revenue requirements (CNPVRR) from the plant with the CNPVRR of alternatives. Tables 3.1 - 3.7 show such comparisons, for various assumptions regarding Pilgrim cost projections and replacement power cost projections. The format of these analyses is taken from BECO's analysis in Appendix 1. The first 14 lines of each table provide data on capital cost recovery, for the entire plant. Lines 14A through 22 display the various Pilgrim cost components, for BECO's share, which is totaled in line 23. Line 26 computes the replacement energy cost, while line 27 provides the replacement capacity cost. The net cost is shown on line 28: negative numbers represent savings due to Pilgrim operation. The last three columns of lines 15-23 and 26-28 show the present values of the cash flows at discount rates of 10.34% (BECO's cost of capital in 85-271), 15%, and 20%. For each discount rate, line 29 computes the ratio of the present value of net cost (if that is positive) to the present value of the capital cost recovery items (lines 15, 16, 17, and 20), to determine what percentage of BECO's existing and future capital costs would be written off under the used-and-useful rule.

Figures on line 29 of more than 100% indicate that all current investment and all capital additions would be written off.

Table 3.1 presents the case of all Historic and Unfavorable inputs to the analysis: continuation of Pilgrim's experience in capacity factor, O&M, and capital additions, low oil prices, ample power supplies, a short Pilgrim life, and high decommissioning costs. Pilgrim is a net loser for ratepayers by $1.0 billion to $1.6 billion: that loss is 1.75 times as much as the cost recovery on investment (both sunk and future capital additions). If Pilgrim's experience continues and replacement power is not much more expensive than currently expected, the used-and-useful rule would require the write-off of all Pilgrim investment to date, and all future capital additions.

While it was not constructed to determine the cost-effectiveness of restarting Pilgrim, Table 3.1 can be used for that purpose. If the net cost, minus the unavoidable costs (such as decommissioning and recovery of sunk costs), is still positive, restart would be more expensive than abandonment. Table A4-C calculates the present value of the capital recovery of Pilgrim's sunk costs for the 1997 retirement date assumed in Table 3.1. Depending on the discount rate, the capital recovery costs $0.3 to $0.5 billion. From line 21 of Table 3.1, the present value of decommissioning is about $0.1 billion. Thus, adjusted for the unavoidable costs, the net cost of returning Pilgrim to service

is $0.6 to $1.0 billion.[5] Pilgrim should be abandoned immediately if the projections in Table 3.1 are correct.

Table 3.2 displays the result of using all of our Improved and Intermediate inputs in the analysis. Pilgrim is still a net loser, costing ratepayers $0.6 to $1.0 billion, which is just about the value of the capital recovery costs. Again, all current and future Pilgrim investment would be written off. Since much of the future capital cost recovery costs are due to capital additions which are still avoidable, it would be less expensive to abandon Pilgrim than to return it to service, under this scenario.

Table 3.3 calculates the useful portion of Pilgrim using all Optimistic and Favorable inputs. Due to the high prices of oil assumed in the avoided cost analysis, Pilgrim is a net winner by $0.5 to $1.5 billion. However, these high oil prices are extremely unlikely to represent long-run avoided costs, since such a large amount of conservation, QF capacity, Canadian purchases, and utility-owned coal capacity would be economical at these prices.[6]

5. In addition, some of the O&M costs in the next few years may be unavoidable. Most of these costs should probably be credited to decommissioning, so the net effect is likely to be quite small.

6. The fact that BECO received 2053 MW of bids at prices below its avoided costs estimates indicates that even the intermediate replacement cost projection (which is based on those same estimates) may be overstated.

Table 3.4 uses the inputs provided by BECO in Exhibit 2 of Appendix 1. On the cost side, this case is similar to the Optimistic case, with still more optimistic capacity factor, decommissioning, O&M and overheads, but less optimistic capital additions. The replacement power costs also use BECO's projections, including the Favorable replacement capacity and energy sources, with Intermediate oil prices. At BECO's cost of capital, Pilgrim is barely cost effective: this result would reverse if the unit were retired a couple of years earlier or if the capacity factor were just 3 points lower. At any higher discount rate, Pilgrim is not cost-effective. Depending on the discount rate, up to 39% of current and future investment could be written off.[7]

Table 3.5 uses all Optimistic inputs as in Table 3.3, except for replacement power costs, which are the most important (and one of the least realistic) factors in making Pilgrim cost-effective. Instead of using the Favorable oil prices, Case 5 uses the Intermediate prices from Table 3.4. With these lower replacement power costs, Pilgrim is not cost-effective; it costs about $0.2 billion more than it is worth, or 22%-53% of the capital recovery cost. Under the used-and-useful rule, 30%-70% of the investment at the end of 1987 would be written off. Assumed replacement

7. This is equivalent to writing off about 65% of the current investment.

energy prices are clearly a very important determinant of Pilgrim cost-effectiveness.[8]

Table 3.6 also differs only slightly from Table 3.3. In Case 6, the supply is changed to the Unfavorable case (lots of capacity is available, including base-load oil), but the oil price is left at the Favorable (high) level. Pilgrim remains cost-effective at BECO's cost of capital, but the margin of net savings is reduced dramatically. At higher discount rates, Pilgrim's costs are essentially equal to its savings. Pilgrim economics are less sensitive to BECO's supply situation (a function of load growth, conservation program effectiveness, QF development, and other factors) than to oil prices.

Table 3.7 takes another look at the sensitivity of the results to oil prices, this time by using the Historic inputs, as in Case 1, except for a longer useful life, and increasing the replacement power costs to the Intermediate level. This is a realistic projection of past cost trends, with a somewhat more optimistic view of Pilgrim's likely longevity. The replace power costs assume a rather modest conservation program and currently projected oil prices. Under these circumstances, Pilgrim would have a net cost of $0.9 to $1.7 billion, well over 100% of total capital recovery, and roughly three times the sunk costs. Pilgrim would not reduce BECO's total costs in even a single

8. At high oil prices, much larger amounts of QFs, conservation, Canadian purchases, and utility-owned coal would be cost-effective, and these would be the real alternatives to returning Pilgrim to service.

year. Table 3.8 may be viewed as a base case, representing a reasonable expectation of future conditions, barring major changes in the economic environment (such as relaxation of NRC standards, vigorous conservation programs, or another oil price shock or collapse).

4 Analyses of Historical Data

This section explains how we derived the costs and other Pilgrim operating parameters. The next section will explain the derivation of replacement power costs, which are the major non-Pilgrim parameters required in the analysis.

Some of the cost input parameters were taken directly from BECO sources, and are therefore not derived in this section. These include:

- Pilgrim capacity: We used the NEPOOL rating of 670 MW.
- Pilgrim fuel costs: We adopted the projection in BECO's 2/86 forecast filing with the EFSC, and the more detailed projection in the Gustin letter (Appendix 1).

4.1 Capacity Factors

We defined the Historic case as a continuation of Pilgrim's own historical performance. This is hardly a worst-case projection, and it is difficult to define a meaningful lower limit on Pilgrim's potential future energy production. Since power plants in general, and nuclear plants in particular, usually undergo a breaking-in process, we used only Pilgrim's mature performance

history, which we defined as starting on January 1, 1978, when the unit had been in operation for just over five years. This calculation, shown in Table 4.1.1, produces an average mature capacity factor of 54%, as of the latest available NRC Operating Reactors report (data through 10/86). This average will fall further before the plant resumes operation: as of the end of June 1987, it would be 50%, and at the end of 1987 it would be 47.6%, assuming Pilgrim remains out of service.

For the Optimistic case, we repeated the mature capacity factor calculation for Vermont Yankee. We again used the NEPOOL rated capacity of 528 MW, which is somewhat conservatively stated: Vermont Yankee is capable of producing more than 528 MW under Optimistic circumstances, such as in cold weather. Since the capacity is understated, the capacity factor is correspondingly overstated. With this statistical advantage, and generally good performance, Vermont Yankee has averaged over 68% mature capacity factor, as shown in Table 4.1.1.

The Improved capacity factor projection was taken from our latest regressions on BWR capacity factors. These regressions, which only include data through 1984 (1985 data is now available, and 1986 data will be available around August 1987), are shown in Table 4.1.2. These are the best-fit equations for capacity factor as a function of unit size, age, and other factors. Table 4.1.3 calculates the results of applying the regressions to Pilgrim. The first line shows the expected capacity factor in years without a refueling outage, while the second line shows the results with a refueling. The third line computes an average

capacity factor, assuming that Pilgrim refuels in two years out of three, which is the refueling pattern generally assumed for BWRs. The right-hand column computes the average of the two more Optimistic cases, which omit the data from the worst accident at a US BWR, the cable fire at Brown's Ferry. The resulting industry-wide average is 54%.

The capacity factor projection based on a regression of industry-wide data closely resembles the projection calculated from the historical experience of Pilgrim. Therefore, our Improved capacity factor projection assumes Pilgrim will partially recover from the decline in performance displayed by the capacity factors of nuclear plants following 1979. The coefficient for Post-79 performance in Table 4.1.2 shows that capacity factors dropped almost 12% after 1979. We have added two-thirds of 12%, or eight percentage points, to the projection based on industry-wide data. The resulting Improved capacity factor is 62%.

4.2 Non-Fuel Station O&M

We based all of our analyses on non-fuel O&M data as reported for each nuclear plant by the operating utility to the FERC in its Annual Report (FERC Form 1).[9] This data shows a strong upward

9. Not all the expenses related to owning and operating the plant are included in this category. For example, pensions, employment taxes, and other employee benefits are not allocated to the plant, even though the direct labor expenses

trend, even after adjustments for inflation. Hence, we estimated the trend in O&M expenses, rather than a simple historical average.

Table 4.2.1 displays the historical O&M experience of Vermont Yankee, and the results of extrapolating that experience and adjusting it to Pilgrim characteristics. The projections in Column 2 assume that annual O&M expense increases at the increment projected by the regression, also shown in Table 4.2.1. Column 3 of Table 4.2.1 adjusts the linear projections to reflect the larger size of the Pilgrim plant, and is then reduced to 75% of the total, which is Boston Edison's share of Pilgrim. This projection, inflated to nominal dollars in Column 4, is used as our Optimistic case of O&M.

Table 4.2.2 presents the results of three regressions on O&M data for all light water reactors in the nation, a total of 535 observations. All costs are stated in 1983 dollars and deflated at the GNP deflator. The equations in this table indicate that real O&M costs for all plants have increased at about 12% annually,[10] and that the economies-of-scale factor (the coefficient of ln(MW/unit) for nuclear O&M is about .5. Doubling

are treated by plant. In addition, legal, regulatory, public relations, and similar home-office functions are excluded from station O&M. We captured these other O&M expenses in the Overhead category.

10. The base of the natural log, e, raised to the coefficient YEAR, e(.11) equals 1.12.

the size of a plant (in Equation 1) or of a unit (in Equations 2 and 3) increases the O&M cost by about 40%.[11]

Equation 1 indicates that, once plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant. Equation 2 measures size as MW per unit, and finds that the effect of adding a second identical unit is about the same as the effect of doubling the size of the first unit. Equation 3 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 2. Indeed, there is a highly significant differential: Northeast plants cost 32% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). We use this equation as the basis for our Improved O&M projection.

Projections based on Equation 3 can be seen in Table 4.2.3. Column 1 increases at a real geometric growth rate, and column 4 grows at the increment between 1988 and 1987. Column 5 inflates the linear projections to nominal dollars, and column 6 is BECO's percentage of the total O&M expense.

The linear projections of O&M based on historical data for all national plants are quite similar to those based on the historical experience of Pilgrim (Table 4.2.4). Either of these

11. In Equation 2, the base of the natural log, e, raised to .53*ln(MW/unit) equals (MW/unit)^.53. If we double the MW size of one unit, the result changes by a factor of 2^.53 = 1.44.

projections could be used as the Historic calculation of Pilgrim O&M costs: we used Pilgrim O&M costs, the more conservative estimates.

Table 4.2.5 summarizes the three methods of calculation of O&M, in real and nominal dollars. The Improved projection is the average of the calculations of O&M based on Pilgrim and Vermont Yankee historical experience.

4.3 Capital Additions

We compiled net annual capital additions for all nuclear power plants reporting total cost data on the FERC Form 1 and DOE compilations of FERC Form 1 data, through 1984.[12] Each plant is included for all years in which no units were added or deleted, and for which the data were not clearly in error. The available experience totaled 520 plant-years of operation. The net capital additions are defined as the difference in plant cost between subsequent years, and are deflated by the appropriate regional Handy-Whitman index for nuclear construction, which itself has increased at 1.4% above the GNP inflation rate. The July, 1984 Handy-Whitman index was estimated by escalating the July 1983 index at the growth rate of the January index from 1983 to 1984.

12. The large steam plant cost data is reported in slightly different formats in various sources and for various years: both the plant cost data and O&M data are now reported on page 403 of the FERC Form 1.

Net capital additions vary with a number of factors, and vary greatly from year to year, complicating statistical analyses. Review of the data indicates that:

- large plants have lower capital additions per kilowatt-year than do small plants,

- multi-unit plants have lower capital additions per kilowatt-year than do single-unit plants,

- Northeastern plants have higher capital additions than those in other parts of the country, and

- capital additions per kilowatt-year have generally been rising over time, despite the greater prevalence of large and multi-unit plants in the later data.

Table 4.3.1 shows the net capital additions experience for Pilgrim and Vermont Yankee from commercial operation date to the present. The average annual net capital additions, measured in $/kw, are 17.76 for Vermont Yankee, and a much higher 54.08 for Pilgrim.[13] Each of these averages was used to project net capital additions for the remaining life of Pilgrim in Table 4.3.4.

Table 4.3.2 presents the annual average net capital additions per kilowatt for all plants for each year since 1972. Over the last seven years, the average for all plants was $27.7/kw-yr; over the last five years, the average has been $32.3/kW-yr.

13. These averages are based on the MGN ratings, which are 687 MW for Pilgrim and 563 for Vermont Yankee.

However, the average capital additions per kilowatt for all plants are likely to be less than those for Pilgrim, for two reasons. First, Pilgrim is a single unit, and twin- or triple-unit plants usually experience lower costs per kilowatt than single units. Second, Pilgrim is a fairly small nuclear unit by current standards, and costs per kilowatt generally decline substantially with unit size. Therefore, Table 4.3.2 also displays annual capital additions for single units between 300 and 800 MW, a size range comparable to Pilgrim. The average net capital additions per kilowatt for these plants since 1978 is $43.6, and for the last five years is $53.14.

Table 4.3.3 displays the results of performing a regression analysis on capital additions data. The regression results were used to project capital additions for a plant with one unit of 687 MW, for each year of Pilgrim's remaining life. The projection shown in Table 4.3.3, reduced to BECO's share, is quite similar to the projection used by BECo, displayed in Table 4.3.4 and in Appendix 1.

Table 4.3.4 summarizes the three methods of projecting capital additions for Pilgrim. Vermont Yankee is once again the Optimistic case, Pilgrim the Historic case, and the projection based on data from all plants is the Improved case. In the cases using averages from Vermont Yankee and Pilgrim data, the average $/kW-yr was multiplied by 75% of the rated capacity of Pilgrim (515 MW, expressed as MGN rating), and divided by 1000 to produce the capital additions for 1983 in millions of dollars. The cost in 1983 dollars was escalated to 1988 dollars by the actual

growth in the GNP deflator from 1983-86, and at an annual rate of 4.3%, BECO's assumed inflation rate, thereafter. The Improved case is the projection based on a regression of national data, described in Table 4.3.3.

Table 4.3.4 displays net capital additions, and therefore understate the true level of capital additions. The net capital additions are the difference between the gross additions (new equipment installed at the plant) and retirements (existing equipment removed from service). Someone must pay for both the new equipment and the undepreciated portion of the investment in the old equipment: ratepayers usually pay for these interim retirements through adjustments to depreciation rates.

To get a rough estimate of the size of the underestimation, we compiled the nuclear additions and retirements data for BECO and for Western Massachusetts Electric Company (WMECO), which owns a portion of the Millstone nuclear units.[14] Table 4.3.5 displays the composition of the net additions in each year. While the retirements are highly variable from year to year, they appear to represent several percent of the net capital additions in normal years, and much less in years (such as Pilgrim in 1984, and presumably in 1986 and 1987 as well) with extraordinary additions. It is clear that our use of net capital additions introduces some optimism, but our sample is too limited (and the

14. The WMECO data is incomplete, because we were unable to obtain the data for all years, and because the 1975 and 1986 additions include the additions of Millstone 2 and 3, respectively.

effect is apparently too small) to justify any explicit correction.

4.4 Decommissioning Costs

BECO projects a total decommissioning cost for Pilgrim of $121.7 million in 1985 dollars, based on a November 1985 update of a 1983 study by Nuclear Energy Services. Based on this estimate, and assuming that Pilgrim would operate until 2008, BECO determined that it would need to collect from its retail ratepayers $5.0 million annually, starting in 1986 and escalating with inflation. We used this projection as our Optimistic case.

The 1985 cost estimate update was 30% higher than the 1983 estimate, even though general inflation between the two estimates was only about 4.3%.[15] In reviewing this estimate, at least two questions are relevant: is the 1985 estimate consistent with estimates for other nuclear plants, and is the 1985 increase in the cost estimate likely to be the last such increase?

Table 4.4.1 lists the decommissioning costs estimated on behalf of other utilities for their nuclear units by TLG Engineering personnel.[16] The Pilgrim estimates are somewhat lower than the

15. This value is based on the growth in the Department of Commerce cost index for non-residential structures.

16. We do not have a comparable listing for Nuclear Energy Service, and are not aware of any other decommissioning cost estimates prepared by that firm.

1985 estimates for comparable-size plants in Table 4.4.1, even though Northeastern labor costs and construction costs tend to be higher than they are elsewhere, and even though Pilgrim's radioactive wastes were assumed to be transported to the Hanford reservation in Washington state for disposal. As can be seen in Table 4.4.1, the 1986 estimate for a slightly smaller Northeastern BWR unit (Nine Mile Point 1) is $212 million, or 74% higher than BECO's estimate.

Just as importantly, the data in table 4.4.1 indicates that decommissioning cost estimates have been rising rapidly for many years. Table 4.4.2 displays the results of a regression analysis on the data from Table 4.4.1: the coefficient of the YEAR variable indicates that TLG cost estimates have been increasing at a compound growth rate of 19% annually in real terms.[17] By comparison, the 1983-85 increase in the Pilgrim estimate was a relatively modest 11.7% annually.

To display the general trends in the industry estimates, the data from Table 4.4.1 and the regression results from Table 4.4.2 (using average values for the set of plants estimated in each year) are graphed in Figure 4.4.1. The pattern of increases in the estimated cost of decommissioning raises considerable question about the validity of the current estimates.

17. See Table 4.4.2 for the regression specification and the derivation of the 19% growth rate. All of the coefficients are highly statistically significant, except for the TWIN coefficient.

It is important to recall that there is little direct experience available in the prompt dismantling (DECON) process for nuclear power plant decommissioning, which BECO (like other utilities) expects to use. The only nuclear power plant to have been DECONed was Elk River, which was decommissioned in 1974.[18] As can be seen in Table 4.4.1, estimated DECON costs have doubled in real terms since 1975: the Elk River experience is clearly out of date.

As significant as the lack of experience is the apparent reluctance of utilities to undertake the DECON process. Table 4.4.3 lists retired nuclear power plants, with their dates of operation. Some of the units have been placed in a "safe storage" mode, but dismantlement has not started at any of them.[19]

Of course, the current estimates could represent the final set of increases in decommissioning cost estimates, and actual decommissioning costs could turn out to be similar to those estimates. However, experience with other nuclear power costs suggests that the industry is characterized more by persistent

18. Portions of the technology have been demonstrated in various capital additions, such as the replacement of steam generators.

19. Perhaps the best example of this reluctance is the Department of Energy's decision to float the reactor pressure vessel of the retired Shippingport unit on a barge, down the Ohio and Mississippi Rivers; through the Gulf of Mexico, the Caribbean and the Panama Canal; along the Pacific Coast to the Columbia River; and finally up the Columbia to DOE's Hanford Reservation. The vessel will then be buried intact. This procedure does not appear to be feasible for commercial-scale units.

cost growth than by cost stability. Virtually all nuclear cost components have been increasing for most of the history of the commercial nuclear power industry:

- The estimated and actual costs of constructing nuclear power plants have been increasing consistently since the late 1960s. Typically, cost estimates for completed plants have increased about 10% annually in real terms (excluding inflation due to schedule slippage) from the issuance of the construction permit to commercial operation.

- Nuclear non-fuel operating and maintenance costs have been increasing (and exceeding expectations) since the early 1970s. Through 1984, the average annual rate of increase was approximately 12-14%.

- Capital additions to nuclear power plants in commercial operation, generally ignored in cost projections into the early 1980s, were significant cost elements in the 1970s: since the Three Mile Island accident capital additions have increased dramatically.

These patterns of cost increases are documented elsewhere in this report, except for construction cost estimate trends, which are discussed in the testimony of Paul Chernick before the DPU on Seabrook, among other places.

The pattern of increases in decommissioning cost estimates, combined with the persistent increases in projected and actual costs for those nuclear cost components with which we have

greater experience, strongly suggests that decommissioning costs will exceed current estimates.

Decommissioning cost estimates have increased for reasons similar to those which have produced large and persistent increases in other nuclear cost components. The earlier estimates have been determined to have underestimated the complexity (and hence the cost) of such problems as disposal of radioactive wastes, and the supervision of workers in radioactive areas. In general, the problems with estimates of other nuclear cost components can be attributed to similar underestimation of the problems inherent in operations as complex as nuclear power production, and the failure to anticipate the costs of complying with nuclear safety regulations.

At historical rates of increase, the estimated cost of decommissioning would double every four to seven years. Considering that the Pilgrim estimate is already below the estimates for comparable plants, it is hardly pessimistic to assume for the Historic case that the real cost of decommissioning will be double that projected by BECO. In addition, the shorter useful life in the Historic case (see below) will allow about half as long as BECO is projecting for collection of the decommissioning cost, requiring twice as large an annual assessment on ratepayers per dollar of real decommissioning cost. Thus, for the Historic case we assumed that the annual decommissioning expense charged to retail ratepayers would be four times BECO's estimate, or $20 million.

The Improved case was set as the average of the Optimistic and Historic cases, at 2.5 times the BECO estimated collection rate, or $12.5 million annually.

Table 4.4.4 summarizes BECO's share of the three decommissioning projections described above.

4.5 Useful Plant Life

BECO estimates that Pilgrim will remain in service until the year 2008, at which time it would be 36 years of age. We used this as the Optimistic projection. This assumption seems to have been established at or near the time Pilgrim entered service, based on the experience of fossil-fired plants at that time. There was then, and there is now, very little experience with the longevity of nuclear power plants. What little experience is available suggests that the useful lives of nuclear units may be much shorter than 36 years.

The five small plants which entered commercial service in the early 1960s would be 20-26 years old today, if all had survived.[20] Of this cohort, Indian Point 1, Humboldt Bay, and Dresden 1 have been retired (formally or de facto), after only

20. This group excludes the exotic demonstration reactors, some of which used liquid metal coolant, organic moderation, and other technologies very different than the light water reactors which have prevailed in US nuclear power plant design. We have also excluded some very small demonstration reactors which operated for only a few years.

12, 13, and 18 years of operation, respectively. Only Big Rock Point and Yankee Rowe remain from that cohort. Even the older and larger of the survivors, Yankee Rowe, has been in service only since 1961, and is thus only 25.[21]

The first units of more than 300 MW went commercial in January 1968: they have just reached age 19. The only clear retirement among this group is Three Mile Island 2, which operated for only a few months prior to its accident. Various nuclear units which are currently on protracted shutdowns due to safety and design problems (such as Browns Ferry) may never reopen, but such units may be shut down for an extended period before it becomes clear that they have reached the end of their useful lives.

To summarize, BECO is projecting that Pilgrim will survive almost twice as long as has the oldest domestic unit over 300 MW, and 50% longer than the oldest domestic commercial power reactor of any size.

Appendix 2 is a paper by Michael B. Meyer, updating the analysis of the operating life of nuclear power plants contained in our earlier report to the NRC (Chernick, et al., 1981). Depending on the data set utilized, the data indicate a median useful life for nuclear power plants of anywhere from 20 to 35 years. Unfortunately, the data, no matter how defined, are quite sparse.

The same forces which resulted in the early retirement of older units are still in operation. High costs of O&M and necessary

21. It is also only a 175 MW unit.

capital additions, mostly driven by regulatory considerations, were responsible for the retirement of most of the small pre-1965 reactors during the 1970s. O&M expenses have continued to grow much faster than inflation, and capital additions have been much higher in the 1980s than in the 1970s.

Pilgrim and other medium-sized nuclear units built in the early 1970s have been less sensitive to O&M and capital additions costs than have the smaller and older units. Economies of scale have made these units more economical to operate than the smaller units. However, as demonstrated in this report, continued growth in real O&M costs at historical rates, especially combined with the continuation of recent rates of capital additions, could render larger (over 300 MW), later (post-1968) nuclear plants prohibitively expensive to operate. Of the post-1968 nuclear units, Pilgrim is especially vulnerable, due to its relatively small size, lack of any sister units to share costs, low historical capacity factors, and design problems due to its early vintage and Mark I containment. The increased regulatory scrutiny resulting from BECO's management problems may further increase future costs.

We use the 25-year life as an Historic projection, and average the 25-year and 36-year projections to produce a 31-year Improved projection.

4.6 Overheads

Not all of the costs associated with operating a nuclear power plant are listed by the utility as O&M costs for that plant. Some categories of costs are accounted for in other types of accounts, such as insurance, payroll taxes, and employee benefits. Table 4.6 displays the overhead expenses for Yankee Atomic, Connecticut Yankee, Vermont Yankee, and Maine Yankee during 1984 and 1985.[22] Line 7 of this table shows the overhead expenses for each plant expressed as a percentage of the total non-fuel station O&M. The percentages vary from 11.9 for Connecticut Yankee in 1984, to 57.6 for Maine Yankee in 1984. The average overhead expense for the four plants from 1984 to 1985 was 26.99%, and is used in calculating the overhead expense for Pilgrim in Section 3 of this paper.

4.7 Sunk Costs and Property Taxes

BECO provided an analysis of the cost of Pilgrim to ratepayers, for a useful life of 40 years.[23] This analysis is reproduced as

22. Yankee Atomic, Connecticut Yankee, Vermont Yankee, and Maine Yankee were chosen for this analysis because of the ease in these cases of determining the overhead expenses pertaining only to the particular nuclear plant.

23. This useful life is based on a recent application to BECO's operating license with the NRC. So far as we know, BECO has

Appendix 1. We modified this analysis for different useful lives by varying the depreciation rate, and compressing the time scale for the deferred taxes. The latter is a simple approximation to a complex pattern, and probably understates the cost of the plant. Future analysis should improve the modeling of deferred taxes, if possible.[24]

Tables 4.7.1 through 4.7.3 show the results of our modifications to the BECO cost recovery pattern. We have deleted the cost components which are included elsewhere in our analysis: capital additions, O&M, fuel, decommissioning,[25] and insurance (included in our Overhead category).

To facilitate analysis of the cost-effectiveness of Pilgrim restart (a task beyond the major thrust of this report), Appendix 4 repeats Tables 4.7.1 through 4.7.3, deleting the "Materials and

not yet proposed using this longer life for accounting or ratesetting purposes. The four-year extension to Pilgrim's operating life might slightly improve the plant's economics, if O&M grows slowly. If O&M grows at historical rates, the longer life would not be beneficial. Subsequent analyses should consider the possibility of life extensions.

24. The BECO analysis includes fairly high levels of capital additions, and a very long useful life, both of which would tend to increase the deferred tax balance, which is generated by (among other things) the difference in tax and book depreciation rates. In our runs with lower capital additions and shorter lives, the use of the BECO cost recovery analysis almost certainly overstates the deferred tax balance, and hence understates the cost of Pilgrim to ratepayers.

25. Despite the decision in DPU 85-271 to allow BECO to collect a total of $5.0 million annually in 1986 dollars, the BECO analysis assumes that the decommissioning contribution is only $4.2 million in 1988 dollars.

Supplies" line. Appendix 4 thus represents the recovery of the sunk costs of Pilgrim as of the end of 1987.

Table 4.8 summarizes the cost inputs calculated in Section 4 for the historic, improved, and optimistic cases.

5 Replacement Power Costs

We analyzed the cost of replacing Pilgrim's capacity and energy contribution in three steps. First, we examined BECO's load and capacity situation for its current capacity plans and for a range of conservation programs, to determine when BECO would require additional capacity to meet its obligations to NEPOOL. Second, we examined the likely range of replacement energy supply sources, which depends in part on the load and capacity forecast. Third, we determined the sensitivity of the replacement energy costs to the projected price of oil.

We have also examined the cost of replacing Pilgrim power for two other utilities. Appendix 3 displays a comparison of replacement capacity and energy costs for Commonwealth Electric Company, Montaup Electric Company and BECO. Replacing Pilgrim capacity is somewhat more expensive for Commonwealth Electric and Montaup, mainly because the need for additional capacity arises earlier for those utilities. However, the higher disadvantage of replacing Pilgrim capacity for Montaup and Commonwealth Electric is more than offset by their lower projected replacement energy costs. Therefore, by using Boston Edison's estimates of replacement costs, we are using the cost estimates most Optimistic to Pilgrim.

5.1 Load and Supply Forecasts

The starting point for this analysis was BECO's most recent reference forecast filed with the EFSC, dated January 17, 1986, and BECO's extension of that forecast to the year 2012, from BECO's RFP for QF power, dated 10/1/86. The BECO load forecast is shown in column 1 of Table 5.1.1. This was taken to be the Favorable case.

The BECO Review Panel (the "Hogan Commission") concluded that it would be "not an unrealistic goal" for BECO's conservation program to aim for a reduction in its 1986 load forecast of 1000 MW by the end of the century. We adopted this level of conservation as an representing a supply situation Unfavorable to Pilgrim, and assumed that the percentage reduction in new load (where efficiency improvements are less expensive) would be twice the percentage reduction in existing 1987 loads. The resulting reductions are 50% for the new loads, and 26% for the existing loads; we assumed the latter would be achieved evenly over the five-year period 1988-92. The results of this projection are shown in columns 2-4 of Table 5.1.1. Note that due to round-off, the total reduction in the year 2000 is 986 MW, slightly less than suggested by the Review Panel. The Review Panel conservation targets are quite modest: much more could be accomplished.

A more detailed study of BECO's conservation potential is justified, both for projection purposes, and to hasten and optimize the development of an efficient conservation program. Such an analysis is long overdue, even if Pilgrim is eventually returned to service, and particularly if it is not.

Capacity projections were also taken from BECO's QF RFP, specifically Appendix C, Exhibit 4. Existing capacity (net of Pilgrim) in 1986 is 2116 MW. BECO projected the addition of 110 MW of power from Ocean states in 1990, 175 MW of Hydro Quebec capacity in 1991, and 283 MW of QFs in 1989 and 1990. BECO is now projecting 512 MW of QFs, ending with a 200 MW addition from the RFP process in 1992.[26] The total capacity additions are listed in the second column of Table 5.1.2. The BECO projections of capacity purchases and sales are also totaled in Table 5.1.2, with the addition of the recently signed contract for purchases of gas turbine (GT) capacity from Northeast Utilities in 1988-93.[27] Finally, Table 5.1.2 sums the existing capacity, capacity changes, and net purchases to derive a total capacity figure for each year.[28]

Tables 5.1.3 and 5.1.4 combine the load forecasts of Table 5.1.1 with the supply forecast of Table 5.1.2. In each case, one of

26. Boston Edison Resource Plan 1987-2000, March 26, 1987.

27. In fact all of the "capacity additions" are also purchases, but BECO splits the categories for some reason. We use the same division as BECO uses.

28. The projections for QF capacity have not been increased to reflect the 2000 MW response to BECO's 200 MW RFP.

the forecasts of territorial load (retail load and the three captive municipals, Wellesley, Norwood, and Concord) is combined with BECO's projection of its demand contract sales to the Reading Municipal, to derive total load.[29] BECO's projected required reserve margin, from the QF RFP (Exhibit 4, Appendix C), is added to the total load to produce projected capability responsibility. Finally, each table compares the projections of capacity to those of capability responsibility, to determine the surplus or deficit in capacity.

Table 5.1.3 shows that, under BECO's forecast, it will run a small capacity deficiency through 1989, without Pilgrim. In 1990, Hydro Quebec and contracted QF capacity eliminate the deficiency. Beginning in 1991, load growth and (more importantly) the termination of existing power purchase contracts cause the deficiency to recur and to grow. BECO would be deficient by its entire 498 MW share of the capacity of Pilgrim in the year 1999.

Table 5.1.4 shows BECO's load and capacity situation under our Unfavorable ("Review Panel") projection. The existing capacity deficiency disappears in 1988 as new purchases increase BECO's

29. The Reading contract projection has not been reduced for conservation programs, for Reading's development of QF capacity, or for the current effort of the Wilmington customers to secede from the Reading system and develop their own QF capacity. At least one of these events is likely, and BECO could encourage both the conservation and the QF development by restrict Reading's access to further power on the demand contract, which is priced below replacement cost.

capability.[30] BECO's capacity surplus approaches 1000 MW in 1991. That surplus dwindles over the subsequent years, but BECO continues to have adequate capacity throughout the forecast period, even without any further additions.[31]

Table 5.1.5 constructs an Intermediate supply situation, using the average of the load levels in the two preceding cases. A small amount of capacity would be required in 1988,[32] but long-term capacity need would not appear until the year 2000, and the entirety of Pilgrim's capacity would not have to be replaced until 2010.

We use these results in two ways. First, the load and capacity comparisons in Tables 5.1.3 through 5.1.4 determine the timing of replacement capacity costs. In the Favorable case, some replacement capacity is required in every year except 1990, and

30. The 1986 and 1987 deficiencies have already occurred (or are in the process of occurring, regardless of whether BECO restarts Pilgrim late this year), and have not had any major reliability consequences. NEPOOL generally has adequate capacity (if the other nuclear plants can stay in service for the summer), and BECO is still receiving credit for Pilgrim's rated capacity, even though the unit has been inoperable for over a year.

31. The surpluses would exist in virtually every year, almost independent of the pattern in which the Review Panel conservation goal is phased in. Slower conservation development would reduce the large surpluses in the early 1990s.

32. Given the low cost of capacity in the very short term, we have ignored this deficiency. BECO might have to pay $10/kW for peaker capacity in 1988, bringing the cost of a 68 MW deficiency to $680,000, which would have a negligible effect on our analyses.

the entire 498 MW capacity must be replaced by 1999.[33] In the other cases, no replacement capacity is required. The pricing of the Favorable case replacement capacity is discussed in Section 5.2.

Second, these comparisons allow us to conclude that, even without any additional capacity, an aggressive conservation program may allow BECO to use more efficient plants to replace Pilgrim than would be the case under its current forecast. This issue is considered in Section 5.3.

33. We assume that BECO would meet the 1988/89 deficiencies by purchasing peaking capacity, rather than building, due to the short lead time. The purchased capacity is likely to be less expensive than new capacity, but we priced all replacement capacity at the levelized real cost for new peaking capacity in BECO's QF RFP.

5.2 Replacement Capacity Costs

In the Favorable and Intermediate cases, we must include some costs for replacing the capacity from Pilgrim. Following BECO's approach, we assume that the capacity will be in the form of gas turbine peaking units.[34]

In its QF RFP, BECO projects a levelized real cost of gas turbine capacity of $48.16/kW-year beginning in 1992, inflating at 4.3% (Appendix C, Exhibit 6, page 5).[35] Table 5.2.1 shows (in column 1) the inflated cost per kW of gas turbine capacity, as assumed by BECO. Column 2 shows the BECO capacity deficit from Table 5.1.3, up to BECO's capacity entitlement in Pilgrim.[36] In column 3 of Table 5.2.1, the number of MW needed in each year is multiplied by the cost per kW in that year, to yield the total replacement capacity cost for each year.

34. As will be discussed in the next section, this assumption is consistent with the adoption of BECO's avoided cost projection for the Favorable replacement energy source.

35. This analysis is somewhat simplified, since O&M and capital recovery costs are combined at the capital cost inflation rate, even though the O&M costs are projected to inflate at a slightly higher rate. Also, existing capacity is available, at lower costs than $48.16/kW-year, through the 1980s and into the early 1990s. Even deficiency charges to NEPOOL are still only $36/kW-year.

36. Any deficits above the 498 MW level would have occurred with or without Pilgrim.

Table 5.2.2 uses the deficit from the intermediate supply case (Table 5.1.5) to calculate replacement capacity cost. There is no deficit for the Unfavorable supply case (Table 5.1.4), and hence no replacement capacity cost.

5.3 Replacement Energy Sources

Replacing the capacity from Pilgrim is a minor part of the cost of replacing the plant. Replacing Pilgrim's energy production will be much more costly than replacing the capacity. We considered two approaches to estimating the replacement cost of Pilgrim energy.

5.3.1 Comparing Pilgrim retirement to QF avoided costs

The first approach was based on the avoided cost projections BECO produced in connection with its RFP for QF power. In its original filing (10/1/86), BECO presented its estimate of the savings per kWh of adding to its planned system (including Pilgrim at a 70% capacity factor and 393 MW of planned QFs at an 80% capacity factor), 200 MW of additional QFs. At the request of EOER, the AG, and other parties interested in the QF proceeding, BECO also ran its production costing model to determine the savings from adding 200 MW of QFs to the existing system, assuming

- Pilgrim capacity factor of 35% and 393 MW of existing QFs,
- Pilgrim capacity factor of 70% and 192 MW of existing QFs, and

- Pilgrim capacity factor of 54% and 192 MW of existing QFs.

All of the QF capacity was assumed to operate at an 80% capacity factor. The last case was filed in the revised RFP (11/21/86), which was approved by the DPU and used in the recent solicitation of bids.

Both the QFs and Pilgrim provide baseload energy.[37] Thus, it would seem that the cost of the baseload energy which the QFs displace would be very similar to the cost of the baseload energy which would be required to replace Pilgrim. If that is the case, then the avoided cost projections from the QF RFP process can be used as reasonable estimates of the cost of Pilgrim replacement energy.

However, the comparison of the QF avoided cost estimates to Pilgrim replacement cost estimates is more complicated by the fact that the QFs rates are calculated for an addition to BECO's system, and the Pilgrim replacement power will compensate for a retirement of existing capacity. Utilities utilize their power plants according to the rules of economic dispatch: the sources with the least expensive running costs are used first (to the extent that they are available), and more expensive plants are turned on only as they are required. Because of this rank-ordering of power supply sources, a 100 MW increase in baseload

37. Some of the contracts negotiated from the RFP process may allow BECO to curtail deliveries, making the QFs more like intermediate or cycling plants. No such curtailments appear to have been contemplated in the production costing runs for the QF RFP.

supply (such as QFs) will have a higher avoided cost per kWh than will a 200 MW increase, since the first 100 MW will back out the most expensive sources, leaving lower-cost plants to be backed out by the next 100 MW increment. Similarly, a 100 MW decrease in baseload power supply will cost more per kWh than a 100 MW addition would save, since the addition replaces the most expensive operating plants, while the decrease requires the utility to fire up the least expensive of the sources it was not previously using: the least expensive non-operating plant should always be more expensive than the most expensive operating plant, or else plants are not being dispatched in economic order.

Suppose we were to hypothesize a basic power supply system for BECO for some future year (say, 1995), and calculate the savings per kwh from adding 200 MW of baseload capacity, and then calculate the cost of retiring 500 MW of baseload capacity from the basic system. Given the factors discussed above, we would expect the retirement to cost much more, per kWh, than the avoided cost calculated for the addition. Since the RFP runs were estimating the average energy savings of adding 200 MW of baseload QF capacity, that energy might not have the same average value as would the energy lost by retiring Pilgrim, which represents 500 MW of baseload capacity.

However, two factors tend to make the QF avoided costs and the Pilgrim replacement costs more similar than they would at first appear. First, BECO did the QF calculation assuming an 80% capacity factor, while various projections of Pilgrim capacity factors range from 54% to 70%. Thus, the amount of energy

supplied by the QFs is closer to that supplied by Pilgrim. Second, unlike the hypothetical discussed in the previous paragraph, the addition of the QFs and the retirement of Pilgrim are being evaluated for different base systems. BECO now projects that it will have much more QF and other third-party capacity than it did when it ran the avoided cost estimates. That additional baseload power will displace much of the most expensive energy sources which BECO included in the QF calculations; retirement of Pilgrim might simply result in BECO reverting to the power supply assumed in the avoided cost calculations.

To determine whether BECO's avoided cost projections can be applied to the cost of replacing Pilgrim, we compared the baseload energy supply situations implied by each case. To place each of the cases on a comparable basis, Table 5.3.1 tabulates the energy available from Pilgrim and QFs for each of the avoided cost estimates and for the replacement of Pilgrim's energy contribution, assuming that Pilgrim would have operated at either the highest capacity factor (70%) or the lowest capacity factor (54%) considered in the cost-effectiveness calculations in Section 3. Table 5.3.1 also displays the center of the increment for each case. Since both Pilgrim and the QFs displace the most expensive sources of power first, the higher the GWH levels displaced (whether measured at the bottom, middle, or top of the increment), the lower the value of the energy displaced.

Figure 5.3.1 displays the range of baseload energy availability underlying each of the four avoided cost estimates and each of

the Pilgrim replacement cases in Table 5.3.1. The bottom of each line corresponds to the amount of baseload energy supplied by Pilgrim and QFs without the incremental resource in the case (either Pilgrim or 200 MW additional QFs).[38] The top of the line corresponds to the energy supply including the incremental resource, and the length of the line represents the energy supplied by the incremental resource. Figure 5.3.1 labels each increment with the case code used in Table 5.3.1, and displays the average levelized avoided cost for each of the avoided-cost cases.

Several points can be observed from the data in Table 5.3.1 and Figure 5.3.1. First, the increase in projected QF capacity since the time of the RFP (including the capacity from the RFP itself) largely offsets the larger size of Pilgrim, making the ranges of replacement energy comparable between the avoided cost calculations and the Pilgrim replacement cost calculations. At the bottom of the increment, the revised RFP filing (labeled AC4 in Table 5.3.1) starts at 3701 GWH, while the Pilgrim replacement cases start just slightly lower, at 3588 GWH.[39] Comparing the top of the increments, it is clear that the last GWHs supplied by Pilgrim would be higher in the loading order and thus less valuable than the corresponding GWHs from the QF calculations.

38. BECO would have other baseload resources, including Hydro Quebec, the Yankees, Pt. Lepreau, and (depending on the definition of baseload) Canal and New Boston. These resources would be constant in each case, so we need not explicitly consider them.

39. The 113 GWH difference is equivalent to just 16 MW operating at an 80% capacity factor.

Comparing the average GWH provided by the incremental supply in each case, we see that the middle of the increment for the Pilgrim replacement case with a low capacity factor (PR1) lies between those of BECO's final avoided-cost run (AC4) and the next highest-increment run (AC3, which uses a 35% Pilgrim capacity factor). The middle of the increment for the high-capacity-factor Pilgrim replacement case (PR2) is almost identical to that of AC2, and is much higher than the range used in the revised RFP filing.

As shown in Figure 5.3.1, the cost of the replacement power falls as the starting and ending points of the energy increment rise. This is the expected result of economic dispatch. The highest avoided cost case is AC4, which is the lowest of the cases in terms of the range of energy supply involved. AC4 represents a lower (and hence more expensive) energy increment than does the replacement of Pilgrim at any of the capacity factors we have considered in this study.[40] Thus, the use of BECO's avoided energy cost projection (from the revised RFP) as a proxy for the cost of replacing Pilgrim's energy would tend to overstate the actual replacement cost, and that projection is therefore suitable for the Favorable energy supply case.

40. The Pilgrim replacement increment is higher in the loading order (and hence the replacement cost is lower) than is the AC4 increment for all Pilgrim capacity factors above 37.3%. If we assumed Pilgrim would operate at a capacity factor below 37.3%, the energy it displaced would tend to be more valuable than that in AC4, but the low capacity factor would certainly make Pilgrim uneconomic.

5.3.2 Updating oil prices

Table 5.3.2 lists the BECO avoided costs from the revised RFP. It also shows the avoided cost figures adjusted by the ratio of the Summer 1986 reference oil price forecast (on which the RFP runs were based) to the Winter 86/87 oil price forecasts (Low, Reference, and High). The reference price is essentially unchanged,[41] so this adjustment primarily reflects the differences in DRI's three scenarios. In essence, we are assuming that the same units would be used in the same way, regardless of oil prices. This is not quite true: changing oil prices will tend to change the order in which plants are dispatched, will influence BECO's efforts to purchase economy power from other utilities, and will alter the attractiveness of QF power.[42] Since all these changes would moderate the effect of increasing oil prices, we know that the High price columns of Table 5.3.2 are overstated, although we do not know by how much. Ideally, we would prefer to have specific production costing and generation modeling runs for each of the cases (e.g., High,

41. DRI oil price projections changed little from Winter to Spring 1987, as well.

42. Since BECO received offers of 2053 MW in response to its RFP for 200 MW at prices not to exceed the avoided costs listed in Table 5.3.2, those avoided costs (or actually the contracts which could be signed under them) appear to represent a ceiling on the replacement cost of Pilgrim. It is difficult to see how BECO could pay as much for replacement power as is postulated by increasing the avoided cost projections to reflect the DRI High oil price scenario.

Reference, and Low oil prices at high, intermediate, and low Pilgrim capacity factors, and without Pilgrim) we are testing: without incurring the expense and delay required by those modeling efforts, the approximations in Table 5.3.2 are the best available.

Table 5.3.2 also shows the BECO projection of Pilgrim fuel costs. Column 4 is the differences between that projection and the adjusted avoided cost projections, or the difference between Column 2 and Column 3. Those differences are the fuel savings attributable to Pilgrim operation, stated in cents/kWh.

5.3.3 Estimating baseload oil replacement costs

The second approach assumed that the replacement costs could be considerably lower than those projected by the BECO RFP, if BECO pursues a vigorous conservation program and backs out the most expensive energy sources on its system. A review of the load and capacity comparisons in Table 5.1.4 and 5.1.5 indicates that the amount of load BECO will have to meet in the future with its existing resources (that is, net of QF purchases) may be considerably lower than the loads it has carried with those resources in the recent past. Thus, the expensive gas turbines and older Mystic units would operate less, and the marginal unit would more often be efficient units, such as New Boston, Mystic 7, and economy purchases from oil and coal plants of other utilities. We approximated this more favorable supply/demand

balance by treating New Boston as the marginal energy source: in fact, the marginal energy source would sometimes be a more expensive oil unit and sometimes a less expensive purchase.[43]

Table 5.3.3 displays the average heat rate for New Boston for each year, 1981-85, and computes the simple average of the heat rates for those four years, which is 9622.6 BTU/kWh.[44] Table 5.3.2 (in the columns marked "1") converts the Winter 86/87 DRI oil price forecasts for New Boston's 1% sulfur fuel to cents/kWh, based on the average New Boston heat rate. Columns 2 and 3 present BECO's projections of Pilgrim fuel costs, and the columns marked 4 present the differences between BECO's fuel price projection for Pilgrim and the New Boston fuel cost for each of the DRI price projections. These net fuel savings are approximately one third lower than those which result from BECO's avoided cost projections.

43. In some situations (for example, once New Boston output has been backed down to minimum levels), the real alternative to Pilgrim is an increase in the scope of BECO conservation programs. These are likely to be much less expensive than burning oil at existing plants.

44. The "heat rate" for a power plant is the amount of fuel (measured in BTUs) required to produce a kWh of electricity. The higher the heat rate, the lower the efficiency. A heat rate of 3413 BTU/kWh would correspond to an (impossibly high) 100% efficiency. New Boston's heat rate is very low (very good) for a conventional central-station utility power plant: only combined cycle, fuel cell, and cogeneration units operate at much higher efficiencies.

6 Effects of Lengthy Outages

The purpose of this section is to determine the trend in performance of a nuclear power plant returning from an extended outage. We have examined the experience in light of two hypotheses regarding the effects of long maintenance outages on plants with histories of performance problems. The first theory suggests that a nuclear plant with a bad performance from the start of its commercial life will continue to perform poorly, regardless of any extended efforts to repair it. The second theory asserts that a plant with a record of poor performance may change that record by devoting a large time period to maintenance and repairs.

The four plants selected for this analysis were the only ones which met these criteria:

- each plant has been in commercial operation for 8 years,
- each plant has experienced a lengthy outage of at least 10 months,
- each plant has had at least 5 years of poor performance.

The performance for those plants included in this analysis has been measured for the most part by their capacity factors, with an annual capacity factor of 40% or lower indicating poor performance. Capacity factor data and explanations of plant performance were taken from two NRC publications, entitled

Nuclear Power Plant Operating Experience and Licensed Operating Reactors.

Table 6.1 displays the capacity factors for the plants examined in this section. Capacity factors for 1986 are calculated only through October due to delays in NRC publications.

6.1 Palisades

Palisades began its commercial life in late 1971 with two relatively poor years of performance. The plant was shut down for maintenance beginning in August of 1973, and remained out of service until October of 1975. The outage was initiated to repair secondary tube leakage in the steam generator, but a large number of other repairs were accomplished at this time as well. As a result, the plant operated at poor capacity factors from 1973 through 1975, with the worst being in 1974, when the capacity factor dropped to 1.1%.[45]

Following the 25 month outage, Palisades continued to perform badly, with the exception of 1977 and 1985. In November 1975, only one month after the large outage, Palisades was shut down for 60 days for repair of condenser tube leakage. In 1976, after a 5 month refueling process, the plant operated at limited power due to turbine pack pressure limitation. After a successful year

45. Palisades came on line briefly in 1974, but after one month was shut down due to condenser tube leakage.

in 1977, the capacity factor for Palisades dropped down to 36.5% in 1978, and remained in the mid 40s through 1982. Long refuelings and maintenance problems accounted for the low capacity factors. In 1979 and 1980, the plant was out for eight and a half months for refueling and TMI related modifications. In 1984, the capacity factor dipped to 11.3%.

Palisades is an obvious example of a bad performer, from commercial operation until today. The plant was out of service for two years, but the outage failed to improve the plant performance by any significant amount. In fact, the plant has had three eight-month outages since the initial two-year outage. Palisades clearly supports the theory that no amount of effort can change a low-performance plant.

6.2 Beaver Valley

Beaver Valley 1 operated with consistently low capacity factors for the first four years of its commercial life. Throughout 1977, 1978 and 1979, the unit experienced forced outages for a total of 15 months. In 1980, Beaver Valley was closed down for eleven months for refueling and TMI related modifications, resulting in a capacity factor of 4%. After 1980, however, the performance of the unit showed much improvement. From 1981 through 1985, the average capacity factor for Beaver Valley was 61%, with only one year of bad performance.

Beaver Valley is an example of a plant that had several bad years when first entering commercial operation, but after eleven months of maintenance improved immensely. The average capacity factor for the first four years of its life was 25.2%, but rose to 60.78% for the five years following the outage. The unit appears to support the theory that an extended outage can improve a plant's performance for its remaining life. However, this conclusion must be tempered by the fact that Beaver Valley's low-performance years were also the first years of its commercial life. The first few years of any plant's operation tend to show lower performance than do the mature years. Therefore, Beaver Valley may just have been slow in maturing, and may not be comparable to units such as Pilgrim, whose poor performance extended or appeared well into their operating lives.

6.3 San Onofre 1

San Onofre 1 entered commercial operation quite successfully, with an average capacity factor of 69% for the first twelve years of life. It was not until 1980 that the unit began to have problems, and it has not recovered since.

In 1980, San Onofre 1 experienced outages for 70% of the year. The first outage was for TMI related modifications, and lasted only 2 weeks. Shortly thereafter, refueling began. The refueling outage was extended for repair of the steam generator tubes, keeping the plant off line for 5 months of 1980 and 6

months of 1981. In 1982, the unit was shut down by the need for seismic backfitting. Questions by the NRC of acceptability of the seismic backfits kept the unit out of service through 1983 and most of 1984. The average capacity factor from 1980 through 1984 was 12%.

San Onofre 1 had a fairly successful year in 1985, achieving a capacity factor of 62.4%. In November 1985, the plant began an outage for refueling and backfit work, which lasted through July, 1986. The unit was out of service again in September for repair to the west main feedwater pump. The capacity factor through October, 1986 dropped to 9.7%.

Since the almost two-year outage of San Onofre 1 is fairly recent, it is difficult to make any conclusions as to its long-term effect. However, the average capacity factor from the end of the outage through October, 1986 was 36.3%, suggesting that the plant's problems are not over. Although there is not much evidence, San Onofre 1 appears to be supporting the theory to the extent that a good plant can become a bad plant, and even a major refitting effort will not automatically cause it to revert to good-plant status.

6.4 Oyster Creek 1

Oyster Creek 1 was a moderately successful unit through 1978, with capacity factors ranging in the upper fifties and lower sixties. In 1979, the unit performed especially well, ending the

year with a capacity factor of 80%. After 1979, however, the unit's performance declined.

Problems began in 1980, when a routine refueling outage was extended to seven months for maintenance reasons. Maintenance problems persisted throughout 1981 and 1982, resulting in capacity factors of 46% and 35% respectively. The most serious outage occurred in 1983, when once again, a scheduled refueling outage was extended to 21 months due to maintenance problems.[46] The capacity factors for 1983 and 1984 were both under 5%.

Although Oyster Creek performed well in 1985 (capacity factor was 66%), the data through October 1986 suggest another poor year. A refueling outage in April of 1986 was continuing in October, indicating more maintenance problems.

It is difficult to estimate the effect of Oyster Creek's 21-month outage because of a lack of followup experience. The fact that the refueling outage in 1986 lasted at least 6 months (the exact length is not available) indicates that maintenance problems are still pervasive. However, it is impossible to estimate which direction Oyster Creek's performance will take for its remaining life. Its history is weak evidence that problems can persist even after several lengthy outages.

Very few firm conclusions can be drawn based on the post-outage data of the four plants available for this analysis. Only two of

46. Reasons for the outage are not mentioned.

the four plants have performed long enough after their outage for a trend to be seen, and each of those plants offers a different conclusion. It remains to be seen what effect the long outages will have in the cases of San Onofre 1 and Oyster Creek. Based on the nuclear power plant data through 1986, neither of our theories of the effects of long maintenance outages can be demonstrated conclusively. Therefore, we may conclude that either outcome is possible, and that neither should be assumed.

7 Potential Future Problems for Pilgrim

7.1 Introduction

Forecasting the future cost-effectiveness of Pilgrim requires forecasting many variables into the future. Three such variables related to Pilgrim's future operations are capacity factor (CF), operations and maintenance expense (O&M), and capital additions (CA). All three of these variables are in turn driven (at least in part) by regulatory actions taken by the U.S. Nuclear Regulatory Commission (NRC). Therefore it is important to attempt to forecast whether or not NRC regulatory requirements will continue to ratchet upwards as they have in the past.

This section of this study attempts to look at this problem in several ways. This section is organized as follows. Subsection 7.2 reviews three independent analysts' analyses of industry-wide O&M and CA data. Subsection 7.3 displays BECO's current (as of 6/8/87) projections, taken from ref. (4), which is also Appendix 1. Subsection 7.4 describes the various lines of NRC research and regulatory activity that might affect the future operations of Pilgrim, focusing mostly on matters relating to the GE Mark I containment. Subsection 7.5 discusses potential future regulatory requirements, again focusing primarily on matters relating to the GE Mark I containment. Subsection 7.6 states brief conclusions, and references are contained in Section 8.

7.2 Independent Analyses of Industry Trends

An initial question to be confronted when analyzing whether or not future regulatory requirements are likely to ratchet upwards or not is whether they have done so in the past, and if they have done so, what has been the effect of this ratcheting. On the issue of whether there has been ratcheting or not, there is widespread agreement by analysts that ratcheting has been substantial and pervasive over time since at least the early 1970s to date. On the issue of what has been the effect of this ratcheting of regulatory requirements, numerous independent analysts have collected and analyzed the national experience and concluded that substantial and persistent increases in both capital additions and O&M have resulted from the ratcheting. This sub-section of this report briefly describes three such analyses.

7.2.1 Analysis by Paul L. Chernick

Paul Chernick, has performed an exhaustive analysis of national, industry-wide nuclear O&M and nuclear capital additions data in reference (1). In that work, Mr. Chernick noted that the national, industry-wide experience for non-fuel O&M appeared to increase in real (i.e., above inflation rates) terms at a rate of about 12% per year, for the years 1968-1984. Ref. (1), Appendix

V-A, pp. V-A-16 through V-A-20; Table V-6; Appendix V-D(data); Appendix V-E (regression specifications). Mr. Chernick also noted that national, industry-wide experience for nuclear capital additions showed upwards trends, above inflation rates, over the period 1972-1984, although the national data was quite variable year-to-year. Ref. (1), Appendix V-A, pp. V-A-21 through V-A-24; Figure V-2; Table V-11; Appendix. V-D (data); Appendix V-F (regressions). Although the capital additions data is confounded with plant aging effects and with changes over time in the size of the average plant (in MW) effects, real (i.e., above inflation) increases of 15% to 20% per year are indicated by the data.

These earlier analyses (done for the New Mexico Attorney General in 1986) described above have been updated for the present study, as described in previous sections of this report.

7.2.2 Analysis by Stephen S. Bernow

Stephen S. Bernow, an analyst working with ESRG in Boston, has also performed a detailed statistical analysis of national, industry-wide nuclear O&M and nuclear capital additions data. Mr. Bernow projects real increases in nuclear O&M costs (i.e., above inflation) of about 3% per year for the next 15 years, and has summarized past national data for the years 1970-1985 as having increased at 11.5% per year above inflation. Ref. (2), p. 22; Ex. SB-5. Similarly, Mr. Bernow projects real increases in

nuclear capital additions (i.e., above inflation) of 2.3% per year for the next 12 years, and has summarized past national data for the years 1970-1985 as having increased at 13.4% per year above inflation. Ref. (2), pp. 32-33; Ex. SB-9.

7.2.3 Analysis by David A. Schlissel

David A. Schlissel has reviewed the statistical projections by ESRG of 2-3% real increases in nuclear O&M and nuclear capital additions in light of past actual experience and in light of past, present, and future NRC regulatory requirements. Ref. (3). Mr. Schlissel's opinion was based largely upon a review of the likely future costs resulting from present regulatory requirements and resulting from future regulatory requirements that will result in turn from present research and regulatory activities and reviews. Mr. Schlissel concluded that continued real escalation (above inflation) was indeed quite reasonable in light of regulatory activity.

7.2.4 Conclusions

Persistent, extremely robust, and widespread increases above inflation have been experienced by the U.S. nuclear power industry over the last two decades with respect to both nuclear O&M and nuclear capital additions. Independent statistical analyses tend to indicate continued real increases above

inflation for both of these types of costs, and the analyses appear reasonable in light of present and expected future regulatory requirements.

7.3 BECO Projections

Although BECO projects an extremely optimistic capacity factor of 70% for Pilgrim 1 for the years 1988-2012, which might be taken to imply a relatively optimistic projection on BECO's part of a relaxation (or at least a stabilization) of NRC regulatory requirements, it is interesting to note that BECO's capital additions and O&M projections are not particularly optimistic. For the year 1987-2012, BECO's projections of net capital additions (in current years' dollars) are as follows:

1987	$150.0 M
1988	$ 40.0 M
1989	$ 40.0 M
1990	$ 70.0 M
1991	$ 40.0 M
1992-2007	5% growth per year in current $
2008-2012	20% reduction per year in current $

Source: Ref. (4), Ex. 1.

Similarly, for the year 1987-2012, BECO's projections for nuclear O&M expense (in current years' dollars) are as follows:

1987	$ 96.5 M
1988	$ 99.0 M
1989	$106.5 M
1990	$119.5 M
1991-2011	5% growth per year in current $

Source: Ref. (4), Ex. 1.

It is interesting to note that BECO's net capital additions projections exceed BECO's depreciation projections for all years through the year 2000, which means that Pilgrim 1 net year-end plant in service is projected to grow through the year 2000 (to $774.0 M in 2000) and to only shrink slowly after 2000 (e.g. to $700.0 M in 2006 and $494.1 M in 2009).

7.4 NRC Research Programs and Regulatory Activities

7.4.1 Research Programs

Four general lines of research over the last 6-8 years have been performed or sponsored by the NRC that bear generally upon the question of the future direction and scope of NRC regulatory activities.

First, the NRC has pursued a line of research related to quantifying safety goals and to applying cost-benefit analysis to safety regulation. See refs. (5), (6), and (7). This line of

research, if followed in actual regulatory activities, would probably tend to slow down the increase in regulatory requirements because the application of cost-benefit screening criteria upon proposed new recation of cost-benefit screening criteria upon proposed new regulatory requirements would increase the burden of proof upon parties advocating increased regulatory requirements. However, it does not currently appear that cost-benefit type criteria will be applied so as to actually hinder regulatory requirements based upon traditional engineering judgment. It seems that the value of safety cannot be adequately quantified by the current state of the art so as to permit cost-benefit analysis of regulatory requirements to be successful.

Second, the NRC has pursued a line of research aimed at improving the quality of probabilistic risk assessments (PRAs), the quantitative studies that attempt to calculate the probabilities of various severe accidents. See refs. (8), (11), and (26) - (31). Recent, more detailed PRAs have not tended to reduce the estimated probabilities of severe accidents and have not tended to narrow the uncertainties associated with those probability estimates.

Third, the NRC has pursued a line of research related to improving "source term" estimates, which are estimates of the expected amount of radioactive materials which would be released by various types of reactor accidents. See refs. (9), (10), and (12) - (25). This line of research has tended to reduce the estimated amounts of radioactive materials (the "source terms") which would be released by various accidents. In general terms, but for the failure of the line of research (labelled <u>second</u>,

above) to produce smaller accident probability estimates, the success of this third line of research in producing smaller source term estimates would have tended to reduce the pressure for future additional regulatory requirements.

Fourth, the NRC has continued to review and study the problems related to various GE BWR containment designs, particularly the GE BWR Mark I design employed at Pilgrim 1 and at about two dozen other U.S. nuclear power plants. This course of review and analysis has not yet resulted in the formation of a formal NRC rulemaking proceeding, but the general trend of work done to date seems to be in the direction of requiring substantial modifications to the Mark I containment. Two of the earliest generic unresolved safety issues (USIs) related to BWR Mark I containment upgrades (USIs No. A-6 and A-7), and produced substantial upgrade requirements for all Mark I's in the late 1970s and early 1980s. See ref. (33). Since these two early USIs affecting Mark I's, it appears that a significant amount of additional information has accumulated to the effect that substantial additional improvements to the Mark I containments have to be made to minimize the chances of a release of radioactivity (i.e., a breach of containment) in the case of a serious loss of coolant accident (LOCA).

7.4.2 Regulatory Activities

The NRC is continually engaged in reviewing licensee event reports (LERs), inspecting operating nuclear power plants, conducting research, issuing research reports, and promulgating regulations, regulatory guides, and generic letters. In a most general sense, the NRC manages generic research and regulation through the unresolved safety issues (USI) process. See refs. (32) - (34). Two examples of this process, relevant to Pilgrim, will illustrate this process.

First, with respect to fire protection regulations, the NRC first focused on the necessity of more formal regulatory scrutiny of fire protection measures immediately after the fire at the TVA's Browns Ferry plant in 1975. A fairly comprehensive set of regulatory requirements (CFR Part 50, Appendix R) were developed by the NRC by the late 1970s. Many nuclear power plants, including Pilgrim, are still in the process of complying with the fire protection regulations of Appendix R in 1987. Indeed, one of the major upgrading efforts by BECO during the current extended Pilgrim outage has been to attempt to finally achieve full compliance with the NRC's fire protection regulations.

Second, with respect to GE BWR Mark I containments, the NRC initially required upgrades for all Mark I's as a result of USIs A-6 and A-7 in the early 1980s. However, evidence has continued to accumulate that Mark I containments still have unacceptably

high probabilities of containment failure during major loss of coolant accidents (LOCAs). BECO has made some containment improvements at Pilgrim during the current outage, apparently attempting to estimate what potential new solutions to the Mark I containment problem will be required by the NRC in the next 3-5 years.

7.5 Potential Future Regulatory Requirements

Continued regulatory attention to the problems inherent in the GE BWR Mark I containment seems highly likely. PRAs continue to indicate unacceptably high probabilities of Mark I containment failure in the case of serious LOCAs. Numerous types of upgrades seem either likely or possible. Hydrogen detection and igniting systems to prevent hydrogen build-up and hydrogen explosions may be required to be upgraded in various ways. Pressure venting, and vent filtering, may be required to be upgraded. The design of certain parts of the concrete containment itself may require modifications. Parts of the design of the suppression pool may require modification and upgrading.

It should be emphasized at this point that the NRC has been resisting pressure to require Mark I containment upgrades at a generic (all plant) level for several years. During this time, the sentiment within the NRC professional staff appears to be increasingly on the side of requiring a Mark I containment rulemaking proceeding, and the pressure for NRC action on a

generic level seems to be growing, both from within and without the NRC. The industry's opposition to any new generic Mark I upgrading requirements has staved off NRC action to date, but it seems somewhat unlikely that this opposition can continue to be effective in light of increasing unanimity at the NRC staff level that the Mark I containment issue needs additional attention in the immediate future.

7.6 Conclusions

1. Past national, industry-wide experience over the last 20 years has revealed a remarkably persistent and robust growth in real terms (above inflation) in both nuclear O&M expense and nuclear capital additions. These cost items have escalated at real rates of 15% to 20% per year over extended periods of time.

2. Nuclear O&M expense and nuclear capital additions have increased in the past due to persistent ratcheting in NRC regulatory requirements.

3. Future cost increases in nuclear O&M expense and in capital additions are highly likely to continue, due to future compliance with existing NRC regulations, regulatory guides, and generic letters, and due to future compliance with future regulations, regulatory guides, and generic letters.

4. Continued changes in GE BWR Mark I containments are one example of an area in which future regulatory requirements seem highly likely.

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for for Tables 5.1 - 5.7.

[1] From Table 4.1.1 or Table 4.1.2, depending on case.
[2] Col [1] x Col [2].
[3] From Table 4.1.3, Escalated at 4.2% annually.
[4] Col [2] x Col [3].
[5] Col [5] from previous year.
[6] 1988 value from Table 4.1.4. Escalated at 4.2% annually.
[7] Col [4] + Col [5] + Col [6]. 1988 value from C. Gustin letter to S. Pollard, 6 / 87, Exhibit 1.
[8] Col [5] from previous year.
[9] Col [10] previous year + .5 x Col [5] / Retirement Date - year + 1.
Depreciation for the last year of plant life requires adding .5 x Col [5] to the above calculation.
[10] Col [7] + Col [8]. 1988 value from C. Gustin letter to S. Pollard, 6 / 87, Exhibit 1.
[11] Col [4] - Col [9].
[12] Deferred Taxes in year x for a plant retiring in year y are evaluated as the taxes assumed in Exhibit 1 of C. Gustin letter to S. Pollard, for year 1987 + x - 1987 x 25 (retirement date-1987).
[13] From C. Gustin letter to S. Pollard, 6 / 87, Exhibit 1.
[14] From C. Gustin letter to S. Pollard, 6 / 87, Exhibit 1.
[15] The sum of Row [11] through [11] - .5 x Col [5].
[16] 75% of Row [15].
[17] 10.34% of Row [16].
[18] 89.66% of Row [15].
[19] 75% of Row [8].
[20] From Table 4.1.3, Escalated at 5.4% annually.
[21] From Table 4.6, [8.85% x Col [18].
[22] 1.85 x 75% of Col [22].
[23] From Table 4.4.3, Escalated at 4.8% annually.
[24] BECO Fuel (From C. Gustin letter) x (498/67) x (Capacity Factor .7).
[25] Sum of Rows [15] through [22].
[26] Row [20] x 100' Generation.
[27] From Table 5.3.4 or 5.3.2, depending on case.
In Case 3.4, the replacement energy from 2019 - 2012 is calculated by escalating the 2008 figure by the average growth rate from the previous ten years.
[28] Col [27] x 100 Generation.
[29] From Table 5.1.1.
In Case 3.4, the replacement capacity cost from 2008 - 2011 is calculated by escalating the 2007 figure by the average growth rate from the previous ten years.
[30] Col 23 - Row 26 - Row 27.

Cases:
M Historical Pilgrim Costs
I Improved Pilgrim Costs/Intermediate Replacement Power Costs
O Optimistic
P Unfavorable to Pilgrim Replacement Power Costs
F Favorable to Pilgrim Replacement Power Costs
B BECO Projections, Appendix 1

TABLE D-1: CALCULATION OF LEVELIZED PORTION OF REVENUE, BASE CASE, 1978 DOLLAR REQUIREMENT CASE

1. Capacity Factor 50.84%
2. BECO Share of Generation (GWH): 2,349
3. Return on Rate Base 10%

	Code	1986	1987	1988	1989	1990	1991	1992	1993	1994
Plant-in-service										
4. Beginning of Year			696.1	846.1	920.8	998.7	1080.0	1164.7	1253.1	1345.2
5. Net Additions	M		150.0	74.7	77.9	81.3	84.8	88.4	92.2	96.1
6. End of Year		696.1	846.1	920.8	998.7	1080.0	1164.7	1253.1	1345.3	1441.5
Accumulated Depreciation										
7. Beginning of Year			152.6	208.8	276.3	352.2	438.1	535.8	648.0	778.3
8. Annual Depreciation			56.2	67.5	75.9	85.9	97.7	112.2	130.2	152.8
9. End of Year		152.6	208.8	276.3	352.2	438.1	535.8	648.0	778.3	931.1
10. Net-Plant (Year-End)		543.5	637.3	644.5	646.5	641.8	628.9	605.1	567.0	509.4
Other Rate Base Items										
11. Deferred Taxes			-103.7	-121.5	-142.1	-145.7	-135.2	-129.5	-114.9	-90.0
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	56.4
14. Average Rate Base			529.6	557.7	536.5	528.7	514.8	507.1	497.2	451.5
14A. BECO Portion			397.2	418.2	402.4	396.5	386.1	380.3	385.4	338.4
Costs										
15. Return on Rate Base			41.1	43.2	41.6	41.0	40.7	39.3	37.8	35.1
16. Income Taxes			15.4	16.2	15.6	15.4	15.2	14.7	14.2	13.2
17. Depreciation			42.2	50.6	57.0	64.4	73.3	84.1	97.7	115.3
18. O&M Expenses	H		56.6	63.5	70.9	79.0	87.7	97.2	107.4	118.4
19. Insurance/Overhead			15.3	17.1	19.1	21.3	23.7	26.2	29.0	32.1
20. Local Taxes			7.6	7.7	7.8	7.7	7.5	7.3	6.8	6.1
21. Decommissioning	H		15.6	16.3	17.0	17.8	18.5	19.3	20.1	21.1
22. Fuel			3.1	15.4	13.6	13.6	13.6	13.6	14.7	15.3
23. Annual Cost			196.9	230.1	242.6	260.2	280.3	301.8	327.7	355.4
24. Cents/Kwh Rate			8.38	9.80	10.33	11.08	11.94	12.85	13.95	15.13
Replacement Energy (Oil Price =U, Supply =U)										
25. Cents/kwh			1.02	1.03	1.19	1.43	1.61	1.74	2.05	2.39
26. $ Million			23.9	24.3	28.0	33.5	37.7	40.9	48.2	51.6
27. Replacement Capacity										
28. Net Cost			173.0	205.8	214.6	225.7	242.6	260.9	279.5	304.8
29. Net Cost as % of Capital Recovery										

[illegible]

[illegible]

Plant-in-Service						
4. Beginning of Year	1441.5	1541.1	1641.4			
5. Net Additions	[illegible]	[illegible]	[illegible]			
6. End of Year	1541.1	1648.4	1788.5			
Accumulated Depreciation						
7. Beginning of Year	901.1	1118.6	1358.8			
8. Annual Depreciation	188.5	237.3	299.1			
9. End of Year	1118.1	1358.2	1788.5			
10. Net-Plant [illegible] Year-End	420.2	291.1	6.0			
Other Rate Base Items						
11. Deferred Taxes	-88.7	25.5	[illegible]			
12. Materials & Supplies	23.5	24	23.5			
13. Nuclear Fuel	81.1	88.1	87.2			
14. Average Rate Base	426.1	363.4	49.1			
144. BEIC Portion	315.5	271.3	23.3			
Costs						
15. Return on Rate Base	33.9	27.9	3.5	121.9	188.9	181.2
16. Income Taxes	12.4	10.8	1.3	57.1	78.4	80.9
17. Depreciation	139.9	175.3	233.4	611.7	459.2	333.5
18. O&M Expenses	139.2	142.2	157.4	538.1	471.2	351.7
19. Interwhite Overhead	35.2	38.1	42.4	153.3	127.5	103.9
20. Local Taxes	5.1	5.5	6.8	23.1	23.5	28.7
21. Decommissioning	21.9	22.3	23.8	116.2	95.1	78.4
22. Fuel	15.4	18.0	18.2	90.3	74.2	61.6
23. Annual Cost	384.1	441.8	548.8	1511.7	1520.2	1241.1
24. Cents per Kwh	15.72	13.55	11.11			
Replacement Energy						
25. Price $/, Energy $.						
26. Demand	1.42	1.76	3.03			
27. Energy	57.1	69.9	71.2	151.1	211.1	181.3
28. Replacement Capacity						
29. Net Cost	227.1	277.3	474.5	1145.4	1223.1	1.01.3
30. Net Cost as % of Capital Costs				17%	17%	17%

TABLE D.2: CALCULATION OF BECO PORTION OF KILGRIM, CASE I: [illegible], INTERMEDIATE REPLACEMENT ENERGY [illegible] Page 1

1. Capacity Factor = 62.00%
2. BECO Share of
 Generation (GWH): 2,705
3. Retirement Date: 2014

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	879.3	911.8	946.8	983.4	1021.4	1061.1	1102.6
5. Net Additions	I		150	32	34	35	37	38	40	41	43
6. End of Year		696.1	846.1	879.3	911.8	946.8	983.4	1021.4	1061.1	1102.6	1145.8
Accumulated Depreciation											
7. Beginning of Year			152.6	187.0	226.7	268.5	312.5	359.1	408.6	461.3	517.7
8. Annual Depreciation			34.4	39.7	41.8	44.1	46.6	49.5	52.7	56.4	60.8
9. End of Year		152.6	187.0	226.7	268.5	312.5	359.1	408.6	461.3	517.7	578.4
10. Net-Plant (Year-End)		543.5	659.1	651.6	643.4	634.3	624.2	612.8	599.8	584.8	567.4
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-127.9	-143.1	-145.7	-142.7	-136.1	-130.9
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	56.4	60.2
14. Average Rate Base			551.4	594.6	577.2	552.1	537.4	523.8	518.5	512.4	502.6
14A. BECO Portion			413.6	446.0	432.9	414.1	403.0	392.9	388.8	384.3	376.9
Costs											
15. Return on Rate Base			42.8	46.1	44.8	42.8	41.7	40.6	40.2	39.7	39.0
16. Income Taxes			16.0	17.3	16.8	16.0	15.6	15.2	15.1	14.9	14.6
17. Depreciation			25.8	29.8	31.3	33.0	35.0	37.1	39.5	42.3	45.6
18. O&M Expenses	I		52.6	59.0	65.9	73.4	81.6	90.4	99.9	110.1	121.2
19. Insurance/Overhead			14.2	15.9	17.8	19.8	22.0	24.4	27.0	29.7	32.7
20. Local Taxes			7.9	7.8	7.7	7.6	7.5	7.4	7.2	7.1	6.8
21. Decommissioning	I		9.8	10.2	10.6	11.1	11.6	12.1	12.6	13.1	13.7
22. Fuel			3.6	17.7	15.7	15.7	15.7	15.7	17.0	17.6	18.8
23. Annual Cost			172.6	203.8	210.6	219.5	230.6	242.9	258.4	274.6	292.3
24. Cents/kwh Rate			6.38	7.54	7.79	8.12	8.52	8.98	9.55	10.15	10.81
Replacement Energy (Oil Price =I, Supply =I)											
25. Cents/kwh			2.7	2.9	3.0	3.2	3.6	4.2	4.7	5.2	5.8
26. $ Million			73.8	77.3	80.3	85.6	96.3	114.5	127.0	141.5	157.4
27. Replacement Capacity											
28. Net Cost			98.8	126.5	129.8	134.0	134.3	128.3	131.4	133.1	134.9
29. Net Cost as % of Capital Recovery											

1. Capacity Factor = 60.00%
2. BECO Share of
 Generation (GWH) : 2,705
3. Retirement Date: 2012

	Case	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005-33 @ 10.84%
Plant-in-service											
4. Beginning of Year		1145.8	1190.8	1237.8	1288.9	1338.0	1391.3	1446.9	1505.0	1565.5	
5. Net Additions	I	45	47	49	51	53	56	58	61	63	
6. End of Year		1190.8	1237.8	1286.9	1338.0	1391.3	1446.9	1505.0	1565.5	1628.6	
Accumulated Depreciation											
7. Beginning of Year		578.4	643.9	715.2	793.4	879.9	976.9	1087.4	1216.9	1376.1	
8. Annual Depreciation		65.5	71.3	78.2	86.5	97.0	110.6	129.5	159.1	252.5	
9. End of Year		643.9	715.2	793.4	879.9	976.9	1087.4	1216.9	1376.1	1628.6	
10. Net-Plant (Year-End)		546.9	522.6	493.5	458.1	414.5	359.5	288.0	189.4	0.0	
Other Rate Base Items											
11. Deferred Taxes		-125.7	-121.5	-116.2	-110.3	-103.8	-96.7	-25.5	66.3	)	
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.9	
13. Nuclear Fuel		66.1	67.2	75.4	75.4	84.2	84.2	92.2	93.9	99.3	
14. Average Rate Base		495.8	477.4	473.4	450.5	450.1	418.8	412.3	363.0	113.5	
14A. BECO Portion		371.8	358.1	355.0	337.9	337.6	314.1	312.7	272.3	85.2	
Costs											
15. Return on Rate Base		39.4	37.0	36.7	34.9	34.9	32.5	32.4	28.2	8.8	369.0
16. Income Taxes		14.4	13.9	13.8	13.1	13.1	12.2	12.2	10.5	3.3	115.8
17. Depreciation		49.2	53.5	58.6	64.9	72.7	82.9	97.1	119.4	189.4	891.1
18. O&M Expenses	I	133.2	146.1	160.0	174.9	191.1	208.4	227.1	247.2	268.8	915.1
19. Insurance/Overhead		35.9	38.4	43.2	47.2	51.6	56.3	61.3	66.7	72.5	247.0
20. Local Taxes		6.6	6.3	5.9	5.5	5.0	4.3	3.5	2.3	0.0	51.7
21. Decommissioning	I	14.3	14.9	15.5	16.2	16.9	17.6	18.4	19.2	20.0	104.0
22. Fuel		20.7	21.0	23.6	23.6	26.3	26.3	28.8	29.4	31.1	151.5
23. Annual Cost		312.6	332.0	357.2	380.3	411.5	440.5	480.8	522.8	593.9	2185.4
24. Cents/Kwh Rate		11.56	12.28	13.21	14.06	15.22	16.29	17.78	19.33	21.96	
Replacement Energy (Oil Price =I, Supply =I)											
25. Cents/Kwh		6.5	7.4	8.3	9.6	10.8	12.0	13.5	14.6	16.1	
26. $ Million		176.8	200.9	225.3	259.3	292.3	324.5	365.5	394.9	437.7	1181.1
27. Replacement Capacity						4.3	7.1	10.5	14.1	17.9	11.7
28. Net Cost		135.8	131.1	131.9	120.4	115.0	108.9	104.9	113.8	139.2	1710.8
29. Net Cost as % of Capital Recovery											1.1%

1. Capacity Factor = 62.00%
2. BECO Share of Generation (GWe): 2,705
3. Retirement Date: 2004

		Case	CNPUPE @ 15.00%	CNPUPE @ 20.00%
Plant-in-service				
4. Beginning of Year				
5. Net Additions		I		
6. End of Year				
Accumulated Depreciation				
7. Beginning of Year				
8. Annual Depreciation				
9. End of Year				
10. Net-Plant (Year-End)				
Other Rate Base Items				
11. Deferred Taxes				
12. Materials & Supplies				
13. Nuclear Fuel				
14. Average Rate Base				
14A. BECO Portion				
Costs				
15. Return on Rate Base			243.8	196.4
16. Income Taxes			98.5	79.2
17. Depreciation			323.2	258.1
18. O&M Expenses		I	769.0	624.7
19. Insurance/Overhead			207.5	168.6
20. Local Taxes			44.6	36.2
21. Decommissioning		I	88.2	71.6
22. Fuel			125.8	101.0
23. Annual Cost			1919.8	1550.7
24. Cents/kwh Rate				
Replacement Energy				
(Oil Price =I, Supply =I)				
25. Cents/kwh				
26. $ Million			874.3	624.8
27. Replacement Capacity			6.2	3.2
28. Net Cost			781.5	619.0
29. Net Cost as % of Capital Recovery			110%	109%

1. Capacity Factor = 68.0%
2. 2011 Share of
 Generation (GWh) = 2,984
3. Retirement Date: 2018

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994
Plant-in-service										
4. Beginning of Year			696.1	846.1	864.5	883.8	903.9	924.7	946.5	968.2
5. Net Additions	0		150.0	18.4	19.2	20.1	20.9	21.8	22.8	23.7
6. End of Year		696.1	846.1	864.5	883.8	903.9	924.7	946.5	968.2	991.9
Accumulated Depreciation										
7. Beginning of Year			152.6	180.7	212.8	245.9	280.0	315.2	351.7	388.5
8. Annual Depreciation			28.1	32.1	33.1	34.1	35.2	36.5	37.8	39.4
9. End of Year		152.6	180.7	212.8	245.9	280.0	315.2	351.7	388.5	427.9
10. Net-Plant (Year-End)		543.5	665.4	651.7	637.9	623.8	609.5	594.8	579.7	564.0
Other Rate Base Items										
11. Deferred Taxes			-103.7	-112.9	-121.5	-129.8	-137.9	-145.1	-145.7	-142.7
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	55.4
14. Average Rate Base			557.7	601.6	578.3	557.2	535.6	516.5	503.8	493.9
14A. BECC Portion			418.3	451.2	434.1	417.9	401.7	387.4	377.9	370.4
Costs										
15. Return on Rate Base			43.2	46.7	44.9	43.2	41.5	40.1	39.1	38.3
16. Income Taxes			16.2	17.5	16.8	16.2	15.6	15.0	14.6	14.4
17. Depreciation			21.1	24.1	24.8	25.6	26.4	27.4	28.4	29.6
18. O&M Expenses	0		48.6	54.5	60.9	67.9	75.4	83.5	92.2	101.8
19. Insurance/Overhead			13.1	14.7	16.4	18.3	20.3	22.5	24.9	27.5
20. Local Taxes			8.0	7.8	7.7	7.5	7.3	7.1	7.0	6.8
21. Decommissioning	0		3.9	4.1	4.3	4.4	4.6	4.8	5.0	5.3
22. Fuel			3.9	19.5	17.3	17.3	17.3	17.3	18.7	19.5
23. Annual Cost			159.1	188.9	190.1	200.4	208.5	217.8	230.1	243.1
24. Generator Rate			5.39	6.33	6.47	6.72	6.99	7.30	7.71	8.15
Replacement Energy (Oil Price =F, Supply =F)										
25. Cents/kWh			5.0	5.1	5.3	5.6	6.7	9.3	11.5	13.3
26. $ Million			150.6	150.8	156.7	166.1	201.7	276.3	346.4	396.9
27. Replacement Capacity				7.4	7.4	0.0	4.0	21.5	13.3	19.8
28. Net Cost			7.4	30.6	28.9	34.3	3.8	-80.1	-105.6	-173.4
29. Net Cost as % of Cost Recovery										

1. Capacity Factor = 68.0%
2. SECO Share of
 Generation (MW) = 2,884
3. Plant Start Date: 2009

	Base	1994	1997	1995	1999	2000	2001	2002	2003	2004	
Plant-in-service											
4. Beginning of Year		1017.8	1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.6	1258.3	1294.5
5. Net Additions	0	25.9	26.9	28.1	29.3	30.6	31.9	33.2	34.7	36.2	37.7
6. End of Year		1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.6	1258.3	1294.5	1332.2
Accumulated Depreciation											
7. Beginning of Year		470.2	513.3	558.7	606.5	657.2	711.2	769.1	831.6	899.9	973.2
8. Annual Depreciation		43.1	45.3	47.8	50.7	54.0	57.9	62.6	68.2	73.4	79.1
9. End of Year		513.3	558.7	606.5	657.2	711.2	769.1	831.6	899.9	973.2	1052.3
10. Net-Plant (Year-End)		530.3	511.9	492.2	470.8	447.4	421.3	392.0	358.4	321.2	279.9
Other Rate Base Items											
11. Deferred Taxes		-136.2	-132.9	-129.7	-121.5	-114.9	-105.2	-93.3	-53.6	-36.7	-9.5
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8	48.1
13. Nuclear Fuel		66.1	67.2	75.4	75.4	84.2	84.2	92.2	92.9	99.2	105.1
14. Average Rate Base		478.3	465.3	462.0	446.0	433.1	424.0	415.9	419.1	391.5	384.8
14A. SECO Portion		358.7	349.0	346.5	334.5	329.3	318.0	311.9	314.2	293.7	288.6
Costs											
15. Return on Rate Base		37.1	36.1	35.8	34.6	34.0	32.9	32.3	32.5	30.4	29.8
16. Income Taxes		12.9	13.5	13.4	13.0	12.8	12.3	12.1	12.2	11.4	11.2
17. Depreciation		32.3	34.0	35.9	38.0	40.5	43.4	46.9	51.2	70.0	59.3
18. O&M Expenses	0	123.2	135.1	148.0	161.9	176.8	192.9	210.2	228.8	249.8	270.1
19. Insurance/Overhead		33.2	36.5	39.9	43.7	47.7	52.1	56.7	61.7	67.1	72.9
20. Local Taxes		6.4	6.1	5.9	5.6	5.4	5.1	4.7	4.3	3.6	3.1
21. Decommissioning	0	5.7	6.0	6.2	6.5	6.8	7.1	7.4	7.7	8.0	8.3
22. Fuel		22.8	23.2	26.0	26.0	29.0	29.0	31.8	32.4	34.3	33.2
23. Annual Cost		274.6	290.4	311.2	329.2	353.0	374.7	402.0	430.7	473.6	491.9
24. Cents/kwh Rate		9.20	9.74	10.43	11.03	11.83	12.55	13.47	14.44	15.87	16.49
Replacement Energy (Oil Price =F, Supply =F)											
25. Cents/kwh		16.9	18.8	20.1	21.8	23.0	24.9	27.0	28.5	30.4	32.9
26. $ Million		505.3	560.8	599.7	651.7	687.0	742.0	813.7	850.0	905.9	981.6
27. Replacement Capacity		22.6	28.0	31.5	33.6	35.1	36.6	38.2	39.9	41.6	43.4
28. Net Cost		-253.3	-298.4	-320.1	-356.1	-389.1	-400.9	-449.9	-459.1	-474.0	-533.1
29. Net Cost as % of Cost Recovery											

1. Capacity Factor = 68.03%
2. BECO Share of
 Generation (GWH): 2,884
3. Retirement Date: 2008

	Case	2006	2007	2008	CONSTANT $	CONSTANT $ @ 15.00%	CONSTANT $ @ 20.00%
Plant-in-service							
4. Beginning of Year		1330.2	1371.5	1412.6			
5. Net Additions	0	39.3	41.0	42.8			
6. End of Year		1371.5	1412.6	1455.3			
Accumulated Depreciation							
7. Beginning of Year		1073.3	1166.1	1279.1			
8. Annual Depreciation		92.9	113.0	176.3			
9. End of Year		1166.1	1279.1	1455.3			
10. Net-Plant (Year-End)		205.4	133.5	0.0			
Other Rate Base Items							
11. Deferred Taxes		25.5	66.3	0			
12. Materials & Supplies		50.5	53.1	42.5			
13. Nuclear Fuel		111.3	117.9	124.9			
14. Average Rate Base		373.0	350.3	145.0			
14A. BECO Portion		279.8	262.7	109.5			
Costs							
15. Return on Rate Base		28.9	27.2	11.3	325.7	251.0	199.4
16. Income Taxes		10.9	10.2	4.2	122.1	94.[illegible]	74.7
17. Depreciation		69.6	84.7	132.2	386.6	298.5	237.3
18. O&M Expenses	0	293.3	318.1	344.8	1025.7	677.6	470.0
19. Insurance/Overhead		79.2	85.9	93.0	276.8	182.9	126.9
20. Local Taxes		2.5	1.6	0.0	53.7	42.1	33.8
21. Decommissioning	0	6.7	9.1	9.5	46.8	30.2	24.6
22. Fuel		38.4	40.7	42.1	199.5	134.5	99.6
23. Annual Cost		531.5	577.4	638.1	2337.9	1618.9	1176.2
24. Cents/kWh Rate		17.62	19.35	21.39			
Replacement Energy (Oil Price =F, Supply =F)							
25. Cents/kWh		35.3	36.9	39.8			
26. $ Million		1054.4	1100.9	1187.1	3955.8	2738.9	1999.6
27. Replacement Capacity		45.3	47.3	49.3	187.3	107.4	71.7
28. Net Cost		-566.2	-570.8	-598.3	-1485.3	-854.4	-494.1
29. Net Cost as % of Cost Recovery					0	0	0

TABLE D.4: CALCULATION OF USEFUL PORTION OF PILGRIM, CASE 4: BECO PROJECTIONS

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation = 35% = 2054
3. Plant Book Value = 2012

	Case	1991	1997	1998	1999	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	886.1	926.1	996.1	1036.1	1078.1	1122.2	1168.5
5. Net Additions	B		150	40	40	70	40	42	44.1	46.3	48.6
6. End of Year		696.1	846.1	886.1	926.1	996.1	1036.1	1078.1	1122.2	1168.5	1217.1
Accumulated Depreciation											
7. Beginning of Year			152.6	176.4	204.0	233.2	264.9	299.0	335.1	373.4	414.0
8. Annual Depreciation			23.8	27.6	29.3	31.8	34.1	36.1	38.3	40.6	43.2
9. End of Year		152.6	176.4	204.0	233.2	264.9	299.0	335.1	373.4	414.0	457.2
10. Net-Plant (Year-End)		543.5	669.7	682.1	692.9	731.2	737.1	742.9	748.8	754.5	759.9
Other Rate Base Items											
11. Deferred Taxes			-108.7	-112.9	-121.5	-129.8	-137.9	-143.1	-147.1	-145.7	-140.7
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	56.4	60.2
14. Average Rate Base			582.0	621.2	633.5	638.6	653.7	654.6	660.9	670.1	682.5
14A. BECO Portion			421.5	465.9	467.6	479.7	490.3	490.9	495.7	502.6	511.9
Costs											
15. Return on Rate Base			43.6	48.2	48.3	49.6	50.7	50.8	51.3	52.0	52.9
16. Income Taxes			20.7	22.8	22.9	23.5	24.0	24.1	24.3	24.6	25.1
17. Depreciation			17.8	20.7	21.6	23.7	25.6	27.1	28.7	30.5	32.4
18. O&M Expenses	B		72.4	74.3	78.9	89.6	93.8	98.4	103.4	108.5	114.0
19. Insurance/Overhead	B		3.4	3.5	3.7	3.9	4.1	4.3	4.5	4.7	5.0
20. Local Taxes			8.0	8.2	8.3	8.6	8.8	8.9	9.0	9.1	9.1
21. Decommissioning	B		3.2	3.4	3.6	3.8	4.0	4.3	4.6	4.9	5.2
22. Fuel			4.1	20.2	17.9	17.8	17.6	17.9	19.4	20.1	21.5
23. Annual Cost			173.1	201.2	206.5	220.8	228.9	235.7	245.0	254.4	265.1
24. Cents/kwh Rate			5.67	6.59	6.76	7.23	7.50	7.72	8.02	8.33	8.68
Replacement Energy (Oil Price =I, Supply =F)											
25. Cents/kwh			3.10	3.17	3.26	3.39	3.89	4.94	5.57	6.20	6.86
26. $ Million			94.7	96.9	99.6	103.5	118.7	150.9	170.1	189.2	209.4
27. Replacement Capacity				7.4	7.4	0.0	4.0	21.6	13.3	13.6	20.3
28. Net Cost			78.3	97.0	99.5	117.3	106.2	63.3	61.6	45.5	24.3
29. Net Cost as % of Cost Recovery											

TABLE 3.4: CALCULATION OF LEVELIZED PORTION OF BELLEFIX, UNIT 4: BASE REQUIREMENTS

1. Capacity Factor = 71.00%
2. BESC Share of
 Generation (kWh) = 2054
3. Revenue Data: 1982

	Case	1986	1987	1988	1989	2010	2011	2012	2013	2014	2015
Plant-in-service											
4. Beginning of Year		1217.1	1268.2	1321.8	1378.1	1437.2	1499.3	1564.5	1632.9	1704.7	1780.1
5. Net Additions	B	51.1	53.6	56.3	59.1	62.1	65.2	68.4	71.8	75.4	79.2
6. End of Year		1268.2	1321.8	1378.1	1437.2	1499.3	1564.5	1632.9	1704.7	1780.1	1859.3
Accumulated Depreciation											
7. Beginning of Year		457.3	503.5	552.9	606.1	663.3	725.2	792.5	865.9	946.1	1034.5
8. Annual Depreciation		46.1	49.5	53.1	57.3	61.9	67.3	73.3	80.1	88.5	98.1
9. End of Year		503.5	552.9	606.1	663.3	725.2	792.5	865.9	946.1	1034.5	1132.7
10. Net-Plant (Year-End)		764.7	768.9	772.0	773.9	774.1	772.0	767.1	758.6	745.6	726.6
Other Rate Base Items											
11. Deferred Taxes		-130.5	-126.1	-122.8	-120.5	-120.7	-121.5	-124.9	-118.1	-63.3	-75.1
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.9	48.1
13. Nuclear Fuel		68.1	67.2	75.4	75.4	84.2	84.2	91.2	98.3	99.3	113.1
14. Average Rate Base		696.8	705.7	720.6	729.1	739.2	741.7	751.9	755.1	759.7	781.9
14A. BESC Portion		502.6	529.2	540.4	544.6	554.4	556.3	563.9	566.4	569.7	571.4
Costs											
15. Return on Rate Base		54.0	54.7	55.9	56.3	57.3	57.5	58.3	58.6	58.9	59.1
16. Income Taxes		25.6	25.9	26.5	26.7	27.2	27.3	27.6	27.8	27.9	28.0
17. Depreciation		34.6	37.1	39.8	42.8	46.4	50.4	55.0	60.2	66.4	73.6
18. O&M Expenses	B	119.7	125.6	131.9	138.5	145.4	152.7	160.3	168.4	176.8	185.6
19. Insurance/Overhead	B	5.2	5.5	5.8	6.1	6.4	6.7	7.0	7.4	7.7	8.1
20. Local Taxes		9.2	9.2	9.3	9.3	9.3	9.3	9.2	9.1	8.9	8.7
21. Decommissioning	B	5.5	5.9	6.2	6.6	7.1	7.5	8.0	8.5	9.0	9.6
22. Fuel		23.6	23.9	26.8	26.8	30.0	30.0	32.9	33.5	35.2	37.2
23. Annual Cost		277.4	287.9	302.2	313.3	329.1	341.4	358.3	373.3	391.1	411.1
24. Cents/kwh Rate		9.08	9.40	9.91	10.11	10.78	11.18	11.73	12.23	12.91	13.42
Replacement Energy (Oil Price =I, Supply =F)											
25. Cents/kwh		7.71	8.76	9.68	11.21	12.40	13.70	15.46	16.48	18.26	20.18
26. $ Million		235.4	267.4	295.5	342.1	379.5	418.5	472.9	503.4	557.9	616.4
27. Replacement Capacity		20.6	28.0	31.5	33.6	35.1	36.6	38.2	39.9	41.8	43.4
28. Net Cost		13.4	-7.5	-24.8	-62.6	-85.5	-113.7	-152.7	-169.8	-208.7	-251.8
29. Net Cost as % of Cost Recovery											

TABLE 3.4: CALCULATION OF BECO PORTION OF PILGRIM, CASE 4: BECO PROJECTIONS

1. Capacity Factor = 70.0%
2. BECO Share of
 Generation (GWh): 2054
3. Retirement Date: 2012

	Case	2006	2007	2008	2009	2010	2011	2012	[illegible] @ 17.34%	[illegible] @ 15.01%	[illegible] @ [illegible]%
Plant-in-service											
4. Beginning of Year		1859.8	1942.5	2029.8	2099.7	2155.6	2200.3	2236.1			
5. Net Additions	B	82.2	87.3	69.9	55.9	44.7	35.8	28.6			
6. End of Year		1942.5	2029.8	2099.7	2155.6	2200.3	2236.1	2264.7			
Accumulated Depreciation											
7. Beginning of Year		1132.7	1242.4	1366.4	1506.1	1661.5	1833.6	2025.9			
8. Annual Depreciation		109.7	124.0	139.7	155.4	172.2	192.3	238.8			
9. End of Year		1242.4	1366.4	1506.1	1661.5	1833.6	2025.9	2264.7			
10. Net-Plant (Year-End)		700.1	663.4	593.6	494.1	366.7	210.2	0.0			
Other Rate Base Items											
11. Deferred Taxes		-59.6	-36.7	-8.5	25.5	56.3	115.5	0			
12. Materials & Supplies		50.5	53.1	42.5	34	27.2	21.7	17.4			
13. Nuclear Fuel		111.3	117.9	124.9	93.6	62.4	31.2	0			
14. Average Rate Base		760.7	754.1	717.6	619.3	500.2	360.7	3.1			
14A. BECO Portion		570.5	565.5	538.2	464.5	375.2	270.5	2.3			
Costs											
15. Return on Rate Base		59.0	58.5	55.6	48.0	38.8	28.0	0.2	456.6	332.3	252.5
16. Income Taxes		28.0	27.7	26.4	22.8	18.4	13.3	0.1	216.4	157.5	119.6
17. Depreciation		82.3	93.0	104.8	116.5	129.1	144.2	179.1	359.4	226.4	180.9
18. O&M Expenses	B	194.9	204.6	214.9	225.6	236.9	248.7	261.2	1067.7	717.0	511.7
19. Insurance/Overhead	B	8.5	9.0	9.4	9.9	10.4	10.9	11.4	47.2	31.8	22.8
20. Local Taxes		8.4	8.0	7.1	5.9	4.4	2.5	0.0	75.9	56.0	43.9
21. Decommissioning	B	10.2	10.9	11.6	12.3	13.1	14.0	8.1	50.2	33.2	22.4
22. Fuel		39.7	42.0	44.5	47.1	49.9	52.9	56.2	217.1	148.7	105.7
23. Annual Cost		431.0	453.6	474.2	488.2	501.0	514.5	518.3	2490.5	1700.8	1282.5
24. Cents/Kwh Rate		14.11	14.85	15.53	15.99	16.41	16.85	16.91			
Replacement Energy (Oil Price =I, Supply =F)											
25. Cents/Kwh		22.16	23.48	25.33	27.07	29.26	31.93	34.19			
26. $ Million		676.8	717.1	773.5	826.6	893.6	975.9	1044.2	2489.9	1630.6	935.6
27. Replacement Capacity		45.3	47.3	49.3	51.27	53.27	55.35	57.51	188.9	115.6	74.7
28. Net Cost		-291.1	-310.7	-348.6	-389.7	-445.8	-506.9	-585.3	-109.3	124.6	222.1
29. Net Cost as % of Cost Recovery									0.00%	17.42%	33.15%

[illegible]

1. Depreciation Factor = 80.00%
2. 8870 Sharing of
 Conservation Savings: 2,884
3. Retirement Date: 2018

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994
Plant-in-service										
4. Beginning of Year			696.1	846.1	864.5	883.8	903.9	924.7	946.6	969.2
5. Net Additions	0		150.0	18.4	19.2	20.1	20.9	21.8	22.6	23.7
6. End of Year		696.1	846.1	864.5	883.8	903.8	924.7	946.6	969.2	992.9
Accumulated Depreciation										
7. Beginning of Year			152.6	180.7	210.8	245.9	280.0	315.2	351.7	389.6
8. Annual Depreciation			28.1	30.1	33.1	34.1	35.2	36.5	37.9	39.4
9. End of Year		152.6	180.7	210.8	245.9	280.0	315.2	351.7	389.6	429.1
10. Net-Plant (Year-End)		543.5	665.4	653.7	637.9	623.8	609.5	594.8	579.7	564.0
Other Rate Base Items										
11. Deferred Taxes			-100.7	-111.9	-121.5	-129.8	-137.9	-143.1	-145.7	-142.7
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	56.4
14. Average Rate Base			557.7	601.6	573.8	567.2	535.6	516.5	503.9	492.9
14A. BECO Portion			418.3	451.2	434.1	417.9	401.7	387.4	377.9	370.4
Costs										
15. Return on Rate Base			43.2	46.7	44.5	43.2	41.5	40.1	39.1	38.3
16. Income Taxes			16.2	17.5	16.8	16.0	15.6	15.0	14.6	14.4
17. Depreciation			21.1	24.1	24.8	25.6	26.4	27.4	28.4	29.6
18. O&M Expenses	0		48.6	54.5	61.6	67.9	75.4	83.5	92.3	101.6
19. Insurance/Overhead			13.1	14.7	16.4	18.3	20.3	22.5	24.9	27.5
20. Local Taxes			8.0	7.8	7.7	7.5	7.3	7.1	7.0	6.8
21. Decommissioning	0		3.9	4.1	4.2	4.4	4.6	4.8	5.0	5.2
22. Fuel			3.9	19.5	17.3	17.3	17.3	17.3	18.7	19.5
23. Annual Cost			158.1	189.9	191.1	201.4	208.5	217.6	230.1	243.0
24. Cents/kwh Rate			5.30	6.33	6.47	6.72	6.99	7.29	7.71	8.15
Replacement Energy (1: Price =I, Supply =F)										
25. Cents/kwh			3.10	3.17	3.18	3.26	3.89	4.94	5.57	6.12
26. $ Million			92.5	94.8	97.3	101.1	116.0	147.4	168.3	184.9
27. Replacement Capacity,				7.4	7.4	7.4	4.0	11.6	13.1	13.6
28. Net Cost			65.5	86.9	89.4	94.2	92.5	48.8	50.6	58.5
29. Net Cost as % of Cost Recovery										

1 Capacity Factor = 65.0%
2. BECO Share of
Generation (MW): 2,554
3 Escalate - Year: 2000

	Case	1995	1997	1998	1999	2000	2001	2002	2003	2004	2005
Plant-in-service											
4. Beginning of Year		1017.8	1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.6	1258.3	1294.5
5. Net Additions	0	25.8	26.9	28.1	29.3	30.6	31.9	33.2	34.7	36.2	37.7
6. End of Year		1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.6	1258.3	1294.5	1332.1
Accumulated Depreciation											
7. Beginning of Year		470.2	513.3	558.7	606.5	657.2	711.2	769.1	831.6	899.9	973.2
8. Annual Depreciation		43.1	45.3	47.8	50.7	54.0	57.9	62.6	68.2	73.4	80.0
9. End of Year		513.3	558.7	606.5	657.2	711.2	769.1	831.6	899.9	973.2	1053.3
10. Net-Plant (Year-End)		530.3	511.9	492.2	470.8	447.4	421.3	392.0	358.4	321.3	278.9
Other Rate Base Items											
11. Deferred Taxes		-138.2	-130.9	-125.7	-121.5	-116.9	-105.2	-93.3	-59.6	-36.7	-8.5
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8	48.1
13. Nuclear Fuel		66.1	67.2	75.4	75.4	84.2	84.2	92.2	93.9	99.3	105.1
14. Average Rate Base		478.3	465.3	462.0	446.0	439.1	424.0	415.9	419.1	391.5	384.8
14A. BECO Portion		358.7	349.0	346.5	334.5	329.3	318.0	311.9	314.3	293.7	288.6
Costs											
15. Return on Rate Base		37.1	36.1	35.8	34.6	34.0	32.9	32.3	32.5	30.4	29.8
16. Income Taxes		13.9	12.5	13.4	13.0	12.8	12.3	12.1	12.2	11.4	11.1
17. Depreciation		32.3	34.0	35.9	38.0	40.5	43.4	46.9	51.2	70.0	60.0
18. O&M Expenses	0	123.2	135.1	148.0	161.9	176.8	192.9	210.2	228.8	248.8	271.3
19. Insurance Overhead		33.2	36.5	39.9	43.7	47.7	52.1	56.7	61.7	67.1	72.9
20. Local Taxes		6.4	6.1	5.9	5.6	5.4	5.1	4.7	4.3	3.8	3.1
21. Decommissioning	0	5.7	6.0	6.2	6.5	6.8	7.1	7.4	7.7	8.0	8.3
22. Fuel		22.8	23.2	26.0	26.0	29.0	29.0	31.8	32.4	34.3	36.1
23. Annual Cost		274.6	290.4	311.2	329.1	353.0	374.7	402.0	420.7	473.8	491.9
24. Cents/kWh Rate		9.20	9.74	10.43	11.03	11.83	12.56	13.47	14.44	15.87	16.48
Replacement Energy (Oil Price =I, Supply =F)											
25. Cents/kWh		7.71	8.76	9.68	11.21	12.43	13.70	15.48	16.48	19.28	20.08
26. $ Million		230.0	261.2	288.7	334.4	370.7	408.8	462.0	491.9	544.6	615.1
27. Replacement Capacity		22.6	28.0	31.5	33.5	35.1	36.6	38.2	39.9	41.5	43.2
28. Net Cost		22.0	1.2	-9.1	-38.8	-52.8	-70.8	-99.2	-101.0	-112.7	-138.2
29. Net Cost as % of Cost Recovery											

1. Capacity Factor = 68.39%
2. 55 % Share of
 Generation (MW-) = 1,384
3. Fuel Escal Date: 2000

	Base	2006	2007	2008	[illegible] @ [illegible]%	[illegible] @ [illegible]%	[illegible] @ [illegible]%
Plant-in-service							
4. Beginning of Year		1330.2	1371.5	1412.6			
5. Net Additions	0	38.3	41.0	42.8			
6. End of Year		1371.5	1412.6	1455.3			
Accumulated Depreciation							
7. Beginning of Year		1073.3	1166.1	1279.1			
8. Annual Depreciation		92.9	113.0	176.3			
9. End of Year		1166.1	1279.1	1455.3			
10. Net-Plant (Year-End)		205.4	133.5	0.0			
Other Rate Base Items							
11. Deferred Taxes		25.6	66.3	)			
12. Materials & Supplies		50.5	53.1	42.9			
13. Nuclear Fuel		111.3	117.9	124.9			
14. Average Rate Base		373.0	350.3	146.0			
14A. BEOO Portion		279.8	262.7	109.5			
Costs							
15. Return on Rate Base		28.9	27.2	11.3	325.7	251.0	199.4
16. Income Taxes		10.8	10.2	4.2	121.1	94.0	74.7
17. Depreciation		66.6	84.7	132.2	266.6	203.5	147.3
18. O&M Expenses	0	233.3	318.1	344.8	1025.7	677.6	470.0
19. Insurance/Overhead		79.2	85.9	93.0	276.8	192.9	126.9
20. Local Taxes		2.5	1.6	0.0	52.7	42.1	33.8
21. Decommissioning	0	8.7	9.1	9.5	46.8	33.2	24.6
22. Fuel		38.4	40.7	43.1	190.5	134.5	99.6
23. Annual Cost		531.5	577.4	638.1	2337.9	1618.9	1176.2
24. Cents/kwh Rate		17.82	19.35	21.39			
Replacement Energy (Oil Price =I, Supply =F)							
25. Cents/kwh		22.16	23.48	25.33			
26. $ Million		661.2	700.6	755.7	1994.8	1283.9	863.9
27. Replacement Capacity		45.3	47.0	49.3	167.3	107.4	71.7
28. Net Cost		-175.0	-170.4	-167.0	175.7	208.6	240.6
29. Net Cost as % of Cost Recovery					22.51%	33.15%	52.90%

TABLE D.5A: CALCULATION OF USEFUL PORTION OF PLANT, CASE 6: OPTIMISTIC COSTS, FAVORABLE OIL PRICE, INFLATED $'S [illegible] Page 1

1. Capacity Factor = 68.09%
2. BECO Share of
 Generation (MW) = 2,991
3. Test Years Dates: 1990

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	864.5	883.8	903.8	924.7	946.6	969.3	993.1
5. Net Additions	0		150.0	18.4	19.2	20.1	20.9	21.8	22.8	23.7	24.8
6. End of Year		696.1	846.1	864.5	883.8	903.8	924.7	946.6	969.3	993.1	1017.8
Accumulated Depreciation											
7. Beginning of Year			152.6	180.7	212.8	245.9	280.0	315.2	351.7	389.6	429.1
8. Annual Depreciation			28.1	32.1	33.1	34.1	35.2	36.5	37.9	39.4	41.1
9. End of Year		152.6	180.7	212.8	245.9	280.0	315.2	351.7	389.6	429.1	470.2
10. Net-Plant Year-End		543.5	665.4	651.7	637.9	623.8	609.5	594.9	579.7	564.0	547.6
Other Rate Base Items											
11. Deferred Taxes			-108.7	-112.9	-121.5	-129.8	-137.9	-143.1	-145.7	-142.7	-136.5
12. Materials & Supplies			29	31	33.1	25.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	56.4	60.2
14. Average Rate Base			557.7	601.6	578.8	557.2	535.6	516.5	503.8	493.9	485.4
14A. BECO Portion			418.3	451.2	434.1	417.9	401.7	387.4	377.8	370.4	364.1
Costs											
15. Return on Rate Base			43.2	46.7	44.9	43.2	41.5	40.1	39.1	38.3	37.6
16. Income Taxes			16.2	17.5	16.8	16.2	15.6	15.0	14.6	14.4	14.1
17. Depreciation			21.1	24.1	24.8	25.6	26.4	27.4	28.4	29.6	31.1
18. O&M Expenses	0		48.6	54.5	60.9	67.9	75.4	83.5	92.3	101.8	112.1
19. Insurance Overhead			13.1	14.7	16.4	18.3	20.3	22.5	24.9	27.5	30.3
20. Local Taxes			8.0	7.9	7.7	7.5	7.3	7.1	7.0	6.8	6.6
21. Decommissioning	0		3.9	4.1	4.3	4.4	4.6	4.8	5.0	5.3	5.5
22. Fuel	..		3.9	19.5	17.3	17.3	17.3	17.3	18.7	19.5	21.3
23. Annual Cost			158.1	188.9	193.1	200.4	208.5	217.8	230.1	243.0	257.9
24. Cents/Kwh Rate			5.30	6.33	6.47	6.72	6.99	7.30	7.71	8.15	8.64
Replacement Energy (Oil Price =F, Supply =U)											
25. Cents/kwh			3.83	4.07	4.33	4.63	5.60	6.62	7.97	9.15	10.54
26. $ Million			114.2	121.4	129.7	144.1	166.9	197.4	237.7	273.0	314.3
27. Replacement Capacity											
28. Net Cost			43.8	67.5	63.4	56.3	41.5	20.4	-7.6	-30.0	-56.3
29. Net Cost as % of User Portion											

[illegible]

[illegible] Capacity, Factor = 68.39%
[illegible] Start of
[illegible] Construction Year = 1,984
[illegible] Service Life = 2[illegible]

	Date	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Plant-in-Service											
4. Beginning of Year		1017.8	1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.1	1257.1	1294.5
5. Net Additions	0	25.9	26.9	28.1	29.3	30.6	31.9	33.3	34.7	36.1	37.7
6. End of Year		1043.6	1070.6	1098.7	1128.0	1158.5	1190.4	1223.8	1258.8	1294.5	1332.1
Accumulated Depreciation											
7. Beginning of Year		470.2	513.3	558.7	606.5	657.2	711.2	769.1	831.6	898.9	971.2
8. Annual Depreciation		43.1	45.3	47.8	50.7	54.0	57.8	61.6	66.1	71.4	8
9. End of Year		513.3	558.7	606.5	657.2	711.2	769.1	831.6	898.9	971.2	1[illegible]
10. Net-Plant (Year-End)		530.3	511.9	492.2	470.8	447.4	421.3	392.0	359.8	323.1	283.8
Other Rate Base Items											
11. Deferred Taxes		-118.1	-122.9	-125.7	-128.5	-131.9	-135.2	-93.8	-59.5	-36.7	-8.5
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8	48.1
13. Nuclear Fuel		66.1	67.2	75.4	75.4	84.2	84.2	92.2	92.9	99.3	113.1
14. Average Rate Base		476.3	465.3	462.0	448.0	439.1	424.0	415.9	416.1	291.5	384.9
14A. BECC Portion		358.7	349.0	346.5	334.5	329.3	318.0	311.9	312.1	293.7	288.6
Costs											
15. Return on Rate Base		37.1	36.1	35.8	34.6	34.0	32.9	32.3	32.5	31.4	26.8
16. Income Taxes		13.9	13.5	13.4	13.0	12.8	12.3	11.1	12.2	11.4	[illegible]
17. Depreciation		32.3	34.0	35.9	38.0	40.5	43.4	46.3	51.2	53.1	5[illegible]
18. O&M Expenses	0	123.2	135.1	148.0	161.9	176.8	192.9	210.2	229.3	249.3	27[illegible]
19. Insurance/Overhead		33.2	36.5	39.9	43.7	47.7	52.1	56.7	61.7	67.1	7[illegible]
20. Local Taxes		6.4	6.1	5.9	5.6	5.4	5.1	4.7	4.3	3.8	3.1
21. Decommissioning	0	5.7	6.0	6.2	6.5	6.8	7.1	7.4	7.7	8.1	8.3
22. Fuel		22.8	23.2	26.0	26.0	29.0	29.0	31.9	32.4	34.3	39.1
23. Annual Cost		274.6	290.4	311.2	329.1	353.0	374.7	400.9	430.7	473.9	491.9
24. Cents/Kwh Rate		9.20	9.74	10.43	11.03	11.83	12.55	13.47	14.44	15.87	16.49
Replacement Energy (Oil Price =F, Supply =U)											
25. Cents/Kwh		11.79	13.10	14.51	15.81	17.08	18.67	20.33	21.98	23.47	25.23
26. $ Million		351.7	393.7	433.5	465.6	507.9	557.2	606.4	656.7	7[illegible]	7[illegible]
27. Replacement Capacity											
28. Net Cost		-77.1	-100.3	-121.6	-135.7	-154.9	-182.4	-204.4	-224.9	-226.8	-[illegible]
29. Net Cost as % of Cost Recovery											

1. Capacity Factor = 58.03%
2. 2010 Share of
 Generation (GWh) = 2,994
3. Retirement Date: 2018

					INFLOW @ 10.34%	INFLOW @ 15.00%	INFLOW @ 20.00%
	Base	2006	2007	2008			
Plant-in-service							
4. Beginning of Year		1332.2	1371.5	1412.6			
5. Net Additions	0	39.3	41.0	42.8			
6. End of Year		1371.5	1412.6	1455.3			
Accumulated Depreciation							
7. Beginning of Year		1072.8	1166.1	1279.1			
8. Annual Depreciation		92.9	113.0	176.3			
9. End of Year		1166.1	1279.1	1455.3			
10. Net-Plant (Year-End)		205.4	133.5	0.0			
Other Rate Base Items							
11. Deferred Taxes		25.5	66.3	[illegible]			
12. Materials & Supplies		50.5	50.1	42.5			
13. Nuclear Fuel		111.3	117.9	124.3			
14. Average Rate Base		370.0	350.3	145.0			
14A. BECO Portion		278.5	262.7	109.5			
Costs							
15. Return on Rate Base		28.3	27.2	11.3	325.7	251.0	199.4
16. Income Taxes		10.6	10.2	4.2	122.1	94.0	74.7
17. Depreciation		69.6	84.7	132.2	296.6	203.5	147.3
18. O&M Expenses	0	293.3	318.1	344.6	1025.7	677.6	470.0
19. Insurance/Overhead		79.2	85.9	93.0	276.9	182.9	126.9
20. Local Taxes		2.5	1.9	0.0	53.7	42.1	33.8
21. Decommissioning	0	8.7	9.1	9.5	46.8	33.2	24.6
22. Fuel		38.4	40.7	43.1	190.5	134.5	99.6
23. Annual Cost		531.5	577.4	638.1	2337.9	1618.9	1176.2
24. Cents/kWh Rate		17.82	19.36	21.39			
Replacement Energy:							
25. Price =F, Supply =U)							
25. Cents/kWh		27.09	28.89	30.83	32.90		
26. $ Million		807.8	861.5	919.7	2719.2	1767.8	1199.2
27. Replacement Capacity							
28. Net Cost		-276.3	-284.1	-281.5	-381.3	-148.9	-22.9
29. Net Cost as % of Cost Recovery					[illegible]%	0.00%	[illegible]%

[illegible]

1. Capacity, Factor = 60.84%
2. [illegible]
 Generation (GWh) = 1,349
3. Retirement Date = 2024

	Code	1988	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	920.8	998.7	1080.0	1164.7	1250.1	1345.8	1441.5
5. Net Additions	N		150	75	78	81	85	86	92	96	100
6. End of Year		696.1	846.1	920.8	998.7	1080.0	1164.7	1250.1	1345.8	1441.5	1541.5
Accumulated Depreciation											
7. Beginning of Year			152.6	187.0	227.9	278.7	324.7	381.7	445.2	516.5	596.1
8. Annual Depreciation			34.4	41.0	45.7	51.0	57.0	63.6	71.2	79.7	88.6
9. End of Year		152.6	187.0	227.9	278.7	324.7	381.7	445.2	516.5	596.1	687.7
10. Net-Plant (Year-End)		543.5	659.1	692.9	719.0	755.3	783.0	807.8	829.3	845.1	853.
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-137.9	-143.1	-145.7	-142.7	-138.2	-133.9
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	51	50	50	50.2	50.2	54.4	55.4	61.2
14. Average Rate Base			551.4	614.6	636.7	649.9	672.1	693.6	721.2	745.5	782.7
14A. 8800 Portion			413.6	461.0	477.5	487.4	504.0	520.2	540.9	559.1	572.7
Costs											
15. Return on Rate Base			41.8	47.7	49.4	50.4	52.1	53.8	55.9	57.8	59.1
16. Income Taxes			16.0	17.9	18.5	18.9	19.5	20.1	21.0	21.7	22.1
17. Depreciation			25.8	30.7	34.3	38.3	42.7	47.7	53.4	59.8	67.1
18. O&M Expenses	M		56.6	63.5	70.5	79.0	87.7	97.2	107.4	119.2	132.3
19. Insurance/Overhead			15.3	17.1	19.1	21.3	23.7	26.2	29.0	32.1	35.7
20. Local Taxes			7.9	8.3	8.7	9.1	9.4	9.7	9.9	10.1	10.2
21. Decommissioning	M		15.6	16.3	17.0	17.8	18.5	19.3	20.1	21.0	21.9
22. Fuel			3.1	15.4	13.6	10.6	13.6	10.6	14.7	15.3	15.4
23. Annual Cost			183.1	216.9	231.6	249.3	267.3	287.7	311.5	336.1	363.5
24. Centskwh Rate			7.80	9.23	9.86	10.57	11.38	12.25	13.26	14.31	15.47
Replacement Energy (Oil Price =1, Supply =1)											
25. Cents/kwh			2.7	2.9	3.0	3.2	3.6	4.2	4.7	5.2	5.7
26. $ Million			64.1	67.1	70.2	74.2	83.6	99.5	110.3	122.9	138.7
27. Replacement Capacity											
28. Net Cost			119.0	149.7	161.4	174.9	183.7	188.2	201.1	213.1	224.8
29. Net Cost as % of Capital Recovery											

[illegible] Capacity Factor = 52.0%
[illegible] BECO Share of
[illegible] Generation (GWH): 1,045
[illegible] Per Kilowatt Cents: 1.0

	Case	1985	1987	1989	1993	2000	2001	2111	2113	2014	[illegible]
Plant-in-Service											
A. Beginning of Year		1541.8	1646.4	1755.5	1869.3	1988.0	2111.8	2240.9	2375.6	2516.1	
B. Net Additions	H	105	109	114	119	124	129	135	140	47	
C. End of Year		1646.4	1755.5	1869.3	1988.0	2111.8	2240.9	2375.6	2516.1	2563.8	
Accumulated Depreciation											
D. Beginning of Year		685.7	786.7	901.0	1031.2	1180.7	1354.5	1550.0	1809.4	2127.6	
E. Annual Depreciation		100.9	114.3	130.2	149.5	173.8	195.4	149.4	318.2	554.3	
F. End of Year		786.7	901.0	1031.2	1180.7	1354.5	1550.0	1809.4	2127.6	2682.0	
G. Net-Plant (Year-End)		859.7	854.6	838.1	807.3	757.2	690.9	566.2	388.4	0.0	
Other Rate Base Items											
H. Deferred Taxes		-125.7	-121.5	-105.2	-93.2	-59.6	-26.7	25.5	66.3	0	
I. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.9	
J. Nuclear Fuel		68.1	67.2	75.4	75.4	84.2	84.2	92.2	90.9	99.2	
K. Average Rate Base		778.9	778.3	785.6	765.9	757.6	760.4	658.1	522.1	71.8	
14A. BECO Portion		524.1	583.7	589.2	574.4	568.2	527.6	438.6	391.6	53.9	

Costs											
L. Return on Rate Base		60.4	60.4	60.9	59.4	58.8	54.6	51.0	40.5	5.6	411.8
M. Income Taxes		22.6	22.6	22.8	22.0	22.0	20.4	19.1	15.2	2.1	155.1
N. Depreciation		75.7	85.7	97.7	112.2	130.4	154.1	187.1	238.6	401.2	818.1
O. O&M Expenses	H	143.2	157.0	171.9	188.0	205.3	224.0	244.0	265.6	289.8	983.8
P. Insurance/Overhead		38.6	42.4	46.4	50.7	55.4	60.5	65.9	71.7	77.9	265.5
Q. Local Taxes		10.3	10.3	10.1	9.7	9.1	8.2	6.8	4.7	0.0	70.9
R. Decommissioning	H	22.9	23.8	24.9	25.9	27.0	28.2	29.4	30.7	32.0	196.4
S. Fuel		18.0	18.2	20.5	20.5	22.9	22.9	25.0	25.5	27.0	181.7
T. Annual Cost		391.6	420.4	455.1	488.7	530.9	572.7	628.4	692.4	834.8	3783.0
U. Levelized Rate		16.67	17.90	19.38	11.21	11.80	14.09	16.78	29.49	25.51	
Replacement Energy (Oil Price =I, Supply =I)											
V. Cents/Kwh		6.5	7.4	8.3	9.4	10.8	12.0	13.5	14.6	16.2	
W. $ Million		153.5	174.5	195.7	215.7	253.9	291.9	317.4	342.9	391.1	1,888.5
X. Replacement Capacity						4.2	7.1	10.5	14.1	17.1	53.0
Y. Net Cost		238.1	245.9	259.5	268.0	271.8	283.8	300.6	335.4	426.8	1,894.9
Z. Net Cost as % of Capital Costs											25%

1. Capacity Factor = 80.84%
2. BECO Share of
 Generation (GWH): 2,049
3. Retirement Date: 2014

		ONE/88 @ 15.[illegible]%	ONE/88 @ 20.[illegible]%
Plant-in-service			
4. Beginning of Year			
5. Net Additions			
6. End of Year			
Accumulated Depreciation			
7. Beginning of Year			
8. Annual Depreciation			
9. End of Year			
10. Net-Plant (Year-End)			
Other Rate Base Items			
11. Deferred Taxes			
12. Materials & Supplies			
13. Nuclear Fuel			
14. Average Rate Base			
14A. BECO Portion			
Costs			
15. Return on Rate Base		318.4	250.4
16. Income Taxes		133.7	109.6
17. Depreciation		491.5	391.5
18. O&M Expenses	H	826.8	671.6
19. Insurance/Overhead		228.1	181.3
20. Local Taxes		61.3	50.5
21. Decommissioning	H	141.2	114.6
22. Fuel		109.2	87.7
23. Annual Cost		2345.8	1899.2
24. Cents/KWH Rate			
Replacement Energy (Oil Price =I, Supply =I)			
25. Cents/KWH			
26. $ Million		759.2	542.6
27. Replacement Capacity		6.2	3.2
28. Net Cost		1237.4	906.3
29. Net Cost as % of Capital Recovery		123%	117%

TABLE 4.1.1: MATURE CAPACITY FACTORS

	Vt. Yankee	Pilgrim
Net Electrical Energy from 1/73 through 10/86 [1]:	27,929,917	27,801,096
Hours [2]:	77,351	77,351
Rated Capability [3]:	528	670
Average Capacity Factor [4]:	68.06%	53.84%

Notes: [1] Data through 1982 from Nuclear Power Plant Operating Experience, December, 1979 through January, 1985. Data after 1982 from Licensed Operating Reactors, January, 1984 through November, 1986.
[2] 8760 per year for 8.83 years.
[3] From NEPOOL CELT Report, 1986, winter rating.
[4] Column [1] divided by Column [2], divided by Column [3].

TABLE 4.1.2: RESULTS OF REGRESSIONS ON BWR CAPACITY FACTOR DATA

	Equation 1		Equation 2		Equation 3		Equation 4	
	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat
Constant	68.73%	6.7	74.86%	7.7	67.99%	6.6	74.04%	7.5
Size	-2.55%	-2.1	-2.74%	-2.4	-2.47%	-2.1	-2.68%	-2.3
Age5	4.24%	3.9	3.48%	3.4	4.24%	4.2	3.46%	3.5
Refuel	-10.33%	-4.1	-11.92%	-5	-9.54%	-3.8	-11.07%	-4.6
GT1000	9.86%	2	13.15%	2.8	9.70%	2	12.89%	2.7
Year Indicators								
1978	3.06%	0.7	2.06%	0.5	---	---	---	---
1980	-4.39%	-1	-5.10%	-1.3	---	---	---	---
1981	-7.47%	-1.7	-8.25%	-2	---	---	---	---
1982	-9.32%	-2.1	-10.15%	-2.4	---	---	---	---
1983	-12.09%	-2.8	-13.04%	-3.2	---	---	---	---
1984	-19.05%	-4.5	-20.39%	-5	---	---	---	---
Post-1979	---	---	---	---	-11.30%	-4.2	-11.84%	-4.6
Adjusted R-SQ	0.169		0.199		0.144		0.170	
F-Statistic	5.4		6.3		8.2		9.7	
Observations	216	[8]	213		216	[8]	213	

Notes: [1] SIZE = Design Electrical Rating (DER) in hundreds of MW.
[2] AGE5 = minimum of AGE (years from COD to middle of current year), or 5.
[3] Refuel = number of refuelings in year (usually 0 or 1).
[4] GT1000 = 1, if SIZE > 1000, 0 otherwise.
[5] Indicator = 1 in this year, 0 otherwise.
[6] 1980 or later.
[7] Full calendar years of BWR operation, >800 MW, 1974-84.
[8] Excludes Browns Ferry 1975-76.

TABLE 4.1.3: PROJECTIONS OF BWR CAPACITY FACTOR FOR FY 1981*

	Value of Refuel	Equation 1 1974 Cords.	Equation 1 Post-78 Cords.	Equation 3 1974 Cords.	Equation 3 Post-78 Cords.	Equation 2 Avg. Post-78 Cords.	Equation 4 Avg. Post-78 Cords.	Average Eq. 2 and 4 Post-78 Cords.
Without Refueling [1]	0	53.87%	60.70%	59.31%	62.93%	61.31%	62.22%	61.82%
With Refueling [1]	1	43.54%	51.37%	41.06%	51.01%	52.87%	51.15%	51.11%
Mature Average Calculated from DEP: [2]		46.98%	55.81%	45.98%	54.98%	55.85%	54.95%	54.97%
Mature Average Calculated from MDC: [4]		45.95%	54.57%	44.95%	53.75%	54.60%	53.72%	53.73%

Notes: [1] Calculated for a 655 MW DEP unit with COD in December, 1972.
[2] Mature average reflects refueling in two out of three years.
[3] Equations 2 and 4 exclude the direct effects of the Brown's Ferry cable fire.
[4] DEP capacity factor multiplied by DEP/MDC (655/670).

TABLE 4.2.1: O&M PROJECTIONS BASED ON VERMONT YANKEE EXPERIENCE

Results of Regression on Vt. Yankee O&M Data	
Constant	(232,955)
Year	3,260
R Squared	0.911

Year	Actual O&M Data for Vt. Yankee ($1983) [1]	Projection From Regression ($1983) [2]	Projection Scaled to Pilgrim ($1983) [3]	BECO's Share in Nominal Dollars [4]
1973	10,094	5,023		
1974	10,651	8,283		
1975	13,151	11,543		
1976	12,974	14,803		
1977	15,030	18,063		
1978	16,021	21,323		
1979	18,722	24,583		
1980	27,260	27,843		
1981	29,499	31,103		
1982	35,060	34,363		
1983	46,312	37,623		
1984	41,648	40,882		
1985	43,252	44,142		
1986		47,402		
1987		50,662	41,830	48,587
1988		53,922	44,521	54,506
1989		57,182	47,213	60,922
1990		60,442	49,905	67,872
1991		63,702	52,596	75,396
1992		66,962	55,288	83,534
1993		70,222	57,980	92,331
1994		73,482	60,671	101,835
1995		76,742	63,363	112,096
1996		80,002	66,054	123,168
1997		83,262	68,746	135,109
1998		86,522	71,438	147,980
1999		89,782	74,129	161,848
2000		93,042	76,821	176,782
2001		96,302	79,513	192,857
2002		99,561	82,204	210,152
2003		102,822	84,895	228,753
2004		106,082	87,587	248,750
2005		109,342	90,279	270,239
2006		112,602	92,971	293,324
2007		115,862	95,662	318,114
2008		119,122	98,354	344,727

Notes: [1] From FERC Form 1 or equivalent.
[2] O&M projections from the regression equation.
[3] Column [2] Multiplied by 75%, to calculate BECO's share. Multiplied by (587/582)^.48 to adjust for the larger size of Pilgrim in relation to Vermont Yankee. .48 is the coefficient for MW Unit in the regression equation for national data. See Table 4.2.2.
[4] Column [3] escalated through 1988 with the GNP inflator, and at 5.4% thereafter.

TABLE 4.2.2: RESULTS OF REGRESSIONS ON O&M DATA, ALL DOMESTIC LWR's, 1988-94

	Equation 1		Equation 2		Equation 3	
	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-2.12	-7.94	-2.12	-7.94	-2.19	-8.77
ln(MW) [2]	0.53	21.15	--	--	--	--
ln(UNITS)	0.03	0.56	0.56	12.27	0.70	15.34
YEAR [3]	0.11	28.62	0.11	28.62	0.11	31.24
ln(MW/unit)	--	--	0.53	21.15	0.48	20.23
NE [4]	--	--	--	--	0.29	8.78
Adjusted R-sq.		0.85		0.85		0.87
F statistic		1032.2		1032.2		904.3

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)
[2] MW = number of MegaWatt in MGN.
[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.
[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region).
NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 4.2.3: PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR PILGRIM 1 (1983$)

Year	From Equation #3 (Table 4.2.2), Regression on National Data					
	Stepped Real Growth ($1983)			Linear Real Growth		
	$1983 (1 Unit)	Nominal	BECO Share	1983$	Nominal	BECO Share
	[1]	[2]	[3]	[4]	[5]	[6]
1987	$64,896	$75,078	$56,534	$64,896	$75,078	$56,534
1988	$72,663	$88,957	$66,718	$72,663	$88,957	$66,718
1989	$81,359	$104,983	$78,737	$80,430	$103,783	$77,837
1990	$91,097	$123,835	$92,921	$88,197	$119,951	$89,963
1991	$101,999	$146,215	$109,661	$95,964	$137,582	$103,172
1992	$114,207	$172,555	$129,416	$103,731	$156,726	$117,544
1993	$127,876	$203,640	$152,730	$111,498	$177,558	$133,168
1994	$143,181	$240,325	$180,244	$119,265	$200,182	$150,137
1995	$160,317	$283,619	$212,714	$127,031	$224,733	$168,550
1996	$179,505	$334,712	$251,034	$134,798	$251,351	$188,513
1997	$200,989	$395,010	$296,258	$142,565	$280,183	$210,142
1998	$225,044	$466,170	$349,628	$150,332	$311,408	$233,556
1999	$251,978	$550,150	$412,612	$158,099	$345,182	$258,887
2000	$282,136	$649,258	$486,944	$165,866	$381,696	$286,272
2001	$315,904	$766,220	$574,665	$173,633	$421,146	$315,859
2002	$353,712	$904,253	$678,190	$181,400	$463,744	$347,808
2003	$396,046	$1,067,152	$800,364	$189,167	$509,714	$382,286
2004	$443,447	$1,259,397	$944,547	$196,934	$559,287	$419,473
2005	$496,521	$1,486,274	$1,114,705	$204,701	$612,749	$459,562
2006	$555,946	$1,754,022	$1,315,517	$212,468	$670,342	$502,757
2007	$622,485	$2,070,005	$1,552,504	$220,235	$732,369	$549,277
2008	$696,986	$2,442,911	$1,832,184	$228,002	$799,140	$599,355

Notes: [1] MW=687, NE = 0, Units = 1
[2], [5] Escalated through 1986 at GNP inflator, and at 5.4% thereafter.
[3], [6] Nominal value multiplied by 75%, BECO's share of Pilgrim.
[4] From 1990, projections increase by difference between 1989 and 1988.

TABLE 4.1.4: O&M PROJECTIONS BASED ON PILGRIM EXPERIENCE

Results of Regression on Pilgrim O&M Data		Year	Actual O&M Data for Pilgrim ($1983)	Projection From Regression ($1983)	Projection Scaled to Pilgrim ($1983)	BECO's Share of Nominal Dollars
			[1]	[2]	[3]	[4]
Constant	(296,169)					
Year	4,151	1974	17,827	11,027		
		1975	12,565	15,179		
R Squared	0.922	1976	27,065	19,330		
		1977	23,556	23,481		
		1978	20,310	27,633		
		1979	24,229	31,784		
		1980	32,524	35,935		
		1981	38,526	40,087		
		1982	44,066	44,235		
		1983	47,276	48,389		
		1984	55,772	52,541		
		1985	57,070	56,692		
		1986	65,363	60,843		
		1987		64,994	48,746	56,620
		1988		69,146	51,859	63,489
		1989		73,297	54,973	70,935
		1990		77,448	58,086	79,000
		1991		81,600	61,200	87,729
		1992		85,751	64,313	97,170
		1993		89,902	67,427	107,376
		1994		94,054	70,540	118,400
		1995		98,205	73,654	130,302
		1996		102,356	76,767	143,143
		1997		106,508	79,881	156,992
		1998		110,659	82,994	171,919
		1999		114,810	86,108	188,001
		2000		118,961	89,221	205,317
		2001		123,113	92,335	223,956
		2002		127,264	95,448	244,009
		2003		131,415	98,562	265,575
		2004		135,567	101,675	288,759
		2005		139,718	104,788	313,671
		2006		143,869	107,902	340,433
		2007		148,021	111,015	369,170
		2008		152,172	114,129	400,018

Notes: [1] From FERC Form 1, or equivalent.
[2] O&M projections from the regression equation.
[3] 75% of Column [2].
[4] Column [3] escalated at GNP inflator through 1986, and at 5.4% thereafter.

TABLE 4.2.5: SUMMARY OF PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR PILGRIM ($ THOUSANDS)

	Real 1992 dollars				Nominal Dollars				
Projections:	Optimistic	Improved	Historic		Optimistic	Improved	Historic		BECO
Basis:	Vt Yankee	Average	National	Pilgrim	Vt Yankee	Average	National	Pilgrim	Projections
Year	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1988	44,521	$48,190	54,497	51,859	54,506	$58,997	66,718	63,499	74,150
1989	47,213	$51,093	60,322	54,973	60,922	$65,908	77,837	70,895	76,875
1990	49,905	$53,995	66,147	58,086	67,872	$73,436	89,963	78,999	69,815
1991	52,596	$56,898	71,973	61,200	75,096	$81,562	103,172	87,729	93,750
1992	55,288	$59,801	77,798	64,313	83,534	$90,382	117,544	97,170	98,408
1993	57,980	$62,703	83,623	67,427	92,331	$99,854	133,168	107,376	103,355
1994	60,671	$65,606	89,448	70,540	101,835	$110,117	150,127	118,400	108,517
1995	63,363	$68,508	95,274	73,654	112,096	$121,199	168,550	130,302	113,954
1996	66,054	$71,411	101,099	76,767	123,168	$133,155	188,510	143,142	119,651
1997	68,746	$74,313	106,924	79,881	135,109	$146,051	210,142	156,991	125,634
1998	71,438	$77,216	112,749	82,994	147,980	$159,950	233,556	171,919	131,916
1999	74,129	$80,118	118,575	86,108	161,848	$174,924	258,887	188,001	138,511
2000	76,821	$83,021	124,400	89,221	176,782	$191,050	286,272	205,317	145,437
2001	79,513	$85,924	130,225	92,335	192,857	$208,406	315,859	223,956	152,709
2002	82,204	$88,826	136,050	95,448	210,152	$227,081	347,808	244,009	160,344
2003	84,896	$91,729	141,876	98,562	228,753	$247,164	382,286	265,575	168,362
2004	87,587	$94,631	147,701	101,675	248,750	$268,754	419,473	288,759	176,781
2005	90,279	$97,534	153,526	104,788	270,239	$291,955	459,562	313,671	185,619
2006	92,971	$100,436	159,351	107,902	293,324	$316,879	502,757	340,433	194,900
2007	95,662	$103,339	165,177	111,015	318,114	$343,642	549,277	368,170	204,645
2008	98,354	$106,241	171,002	114,129	344,727	$372,372	599,355	400,018	214,877

Notes: [1] From Column 3, Table 4.2.1.
[2] Average of Columns [2] and [4].
[3] Column [4], Table 4.2.3 * .75.
[4] From Column [3], Table 4.2.4.
[5] From Column 4, Table 4.2.1.
[6] Average of Columns [5] and [8].
[7] Column [6], Table 4.2.3 * .75.
[8] From Column [4], Table 4.2.4. Used as Historic case in Section 3.
[9] From C. Gustin letter to S. Pollard, 6/8/87, Exhibit 2.

TABLE 4.2.1: NET CAPITAL ADDITIONS EXPERIENCE FOR VERMONT YANKEE AND PILGRIM

	Pilgrim				Vermont Yankee			
		Net Capital Additions				Net Capital Additions		
Year	Plant Cost	Nominal (Thousands)	$1983 (Thousands)	$/kW	Plant Cost	Nominal (Thousands)	$1983 (Thousands)	$/kW
1972	321,543	-	-	-	171,141	-	-	-
1973	328,309	-	-	-	184,481	12,439	28,287	50.15
1974	335,892	(3,347)	(6,565)	-10.18	185,158	677	1,348	2.39
1975	336,454	482	892	1.32	185,739	581	1,038	1.84
1976	341,449	4,975	8,208	12.68	190,886	5,147	13,598	24.15
1977	357,579	16,129	25,090	38.71	198,331	2,445	3,801	6.75
1978	361,758	4,179	6,120	6.31	199,837	2,506	3,670	6.52
1979	370,428	8,670	11,577	15.85	204,985	1,989	2,669	4.74
1980	437,966	67,558	83,346	121.02	217,575	16,740	20,652	36.68
1981	458,680	20,694	23,488	34.19	226,115	8,540	9,693	17.22
1982	480,711	22,031	25,350	109.68	231,890	5,775	6,031	10.71
1983	472,831	42,120	42,120	61.31	255,209	23,329	23,329	41.44
1984	639,115	166,284	159,911	232.77	259,556	4,347	4,466	7.93
1985	660,099	20,974	22,246	32.38	272,135	12,579	11,489	20.41
1986	696,063	32,964	29,913	43.54	-	-	-	-
Average:		35,133	37,051	54.08		7,703	10,002	17.76
1980's Average:		60,805	62,039	90.74		11,880	12,610	22.40

Notes: [1] From FERC Form 1, or equivalent.
[2] Deflated at Handy Whitman Index through 1984.
1985 and 1986 data related with GNP Deflator from
Economic Report of the President.
[3] Based on MSN Rating (655 MW through 1977, and 687 MW thereafter).
[4] Based on MSN Rating (593 MW).

TABLE 4.3.2: NUCLEAR CAPITAL ADDITIONS, 1972 - 1984

Year	All plants	Single units, > 800 MW	Single units, 300-800 MW
	Averages by Year (in $/kw-yr)		
1972	$1.43		$1.92
1973	$10.37	$38.90	$8.18
1974	$11.07	$26.32	$8.54
1975	$8.71	$19.72	$3.18
1976	$15.07	$2.98	$19.69
1977	$18.91	$12.78	$32.86
1978	$17.77	$25.94	$19.10
1979	$14.32	$16.75	$20.39
1980	$27.73	$27.97	$37.53
1981	$31.66	$28.33	$42.48
1982	$29.06	$24.30	$44.93
1983	$29.78	$26.42	$56.38
1984	$42.38	$34.45	$84.40
Overall Average:	$20.74	$23.37	$29.20
(# of obs.)	520	127	157
1978-84 Average:	$27.69	$26.49	$43.60
(# of obs.)	314	97	90
1980-1984 Average:	$32.29	$28.30	$53.14
(# of obs.)	224	67	64

TABLE 4.3.C: PROJECTIONS OF NET CAPITAL ADDITIONS, FOR PLANT ($ Thousand

Regression Equation for Capital Additions per Unit

Constant	-31938		1981	11221
			1981	13131
ln (MW per Unit)	8777		1982	11557
			1983	13509
ln(Units)	-12830		1984	22861
			Avg. 1980-84	14478

Real Cost Projections (1982 $), 1 Unit,
687 MW (MIN Rating) [1]: $26,940

BECO's Share: $20,130

Year	Nominal Capital Additions Projections [2]	BECO's Share
1987	$30,251	$22,688
1988	$32,177	$24,133
1989	$33,561	$25,171
1990	$35,304	$26,478
1991	$36,509	$27,382
1992	$38,079	$28,559
1993	$39,716	$29,787
1994	$41,424	$31,068
1995	$43,206	$32,404
1996	$45,063	$33,798
1997	$47,001	$35,251
1998	$49,022	$36,767
1999	$51,130	$38,348
2000	$53,329	$39,997
2001	$55,622	$41,716
2002	$58,014	$43,510
2003	$60,508	$45,381
2004	$63,110	$47,332
2005	$65,824	$49,368
2006	$68,654	$51,491
2007	$71,606	$53,705
2008	$74,685	$56,014

[1] Calculated for a 687 MW unit.
[2] 1982 Calculation escalated by the GNP inflator through 1985,
and at 4.2% thereafter.
[3] 75% of Column [2].

TABLE 4.3.4: SUMMARY OF PROJECTIONS OF CAPITAL ADDITIONS COSTS, $ MILLION

Projection:	Optimistic	Improved	Pessimistic	
Basis:	Vt. Yankee	National	Pilgrim	BECO Projections
Year	[1]	[2]	[3]	[4]
Capital Additions for the Plant in 1983 $:	$11.53		$46.73	
1988	$13.90	$24.13	$58.02	$30.00
1989	$14.42	$25.17	$58.43	$30.00
1990	$15.04	$26.25	$60.95	$52.50
1991	$15.69	$27.38	$63.57	$30.00
1992	$16.36	$28.56	$66.30	$31.50
1993	$17.07	$29.79	$69.15	$33.08
1994	$17.80	$31.07	$72.12	$34.73
1995	$18.57	$32.40	$75.22	$36.45
1996	$19.37	$33.80	$78.46	$38.32
1997	$20.20	$35.25	$81.83	$40.20
1998	$21.07	$36.77	$85.35	$42.23
1999	$21.97	$38.35	$89.02	$44.33
2000	$22.92	$40.00	$92.85	$46.58
2001	$23.90	$41.72	$96.84	$48.90
2002	$24.93	$43.51	$101.01	$51.30
2003	$26.00	$45.38	$105.35	$53.85
2004	$27.12	$47.33	$109.88	$56.55
2005	$28.29	$49.37	$114.60	$59.40
2006	$29.50	$51.49	$119.53	$62.40
2007	$30.77	$53.70	$124.67	$65.48
2008	$32.10	$56.01	$130.03	$52.43

Notes: [1] $22.4/kw x 515 MW/1000, escalated by the GNP inflator through 1986, and at 4.3% thereafter. 515 MW = .75 x 687 MW (Pilgrim MSN rating).
[2] From table 4.3.3. Projections based on regression of national data.
[3] $90.74/kw x 515/1000, escalated by the GNP inflator through 1986, and at 4.3% thereafter. $/kw values are averages from Table 4.3.1.
[4] From C. Gustin letter to S. Pollard, 6/9/87, Exhibit 2. Reduced to 75% of total (BECO's share).

TABLE 4.0.5: CALCULATION OF RETIREMENTS AS A PERCENTAGE OF NET ADDITIONS

FEPC Year	Additions	Retirements	Adjustments and Transfers	Net Additions	Ratio of Retirements to Net Additions
1972	230,829,281			230,829,281	0.0%
1973	7,789,081			7,789,081	0.0%
1974	1,569,652	4,917,515		(3,347,864)	-146.9%
1975	482,151			482,151	0.0%
1976	5,509,050	533,214		4,975,836	10.7%
1977	16,445,030	(306,086)		16,751,116	-1.8%
1978	4,181,162	1,673		4,179,489	0.0%
1979	10,352,458	1,682,794		8,669,664	19.4%
1980	67,848,214	289,482		67,558,732	0.4%
1991	21,056,158	362,697		20,693,460	1.8%
1982	74,965,407	2,934,671		72,030,737	4.1%
1983	44,887,114	2,767,020		42,120,095	6.6%
1984	167,749,578	1,355,351		166,394,227	0.8%
1985					
1986	36096312.31	3121909		32,964,403	
Total	689,750,648	17,660,240		672,090,408	

WMECO Year	Additions	Retirements	Adjustments and Transfers	Net Additions	Ratio of Retirements to Net Additions
1972	112,142			112,142	0.0%
1973	527,445	220,904	(32,765)	273,776	80.7%
1974	(82,235)	(205,241)	(137,735)	(15,729)	1304.9%
1975					
1976	5,980,069		514,698	6,494,767	0.0%
1977	5,125,571	430,050		4,695,521	9.2%
1978	5,272,199	145,746		5,126,453	2.8%
1979	3,017,303	249,203		2,768,100	9.0%
1980	5,219,725	2,755		5,216,970	0.1%
1981	19,247,332	576,775		18,670,557	3.1%
1982					
1983	7,075,606	432,959		6,642,647	6.5%
1984	5,281,345	275,975		5,005,370	5.5%
1985	783,484	413,303		370,181	111.6%
Total	57,558,986	2,542,429	344,198	55,360,755	

Source: FEPC Form 1 or Return of the Company.

TABLE 4.4.1: TLG DECOMMISSIONING ESTIMATES, CONSTANT DOLLARS

Plant Station	Base Year	Estimated Cost Unit (Base Year Dollars)	Estimated Cost Unit ($1988, Millions)[2]	MW	PWR [3]	TWIN [4]
Fermi 2	1978	97	107	1056	0	0
Monticello	1979	44	65	536	0	0
Prairie Island 1&2	1979	33	49	530	1	0.5
Brunswick 1	1979	48	71	790	0	0
Brunswick 2	1979	37	55	790	0	1
Robinson	1979	28	41	665	1	0
Exeter	1981	52	64	900	1	0
Surry	1981	108	125	490	1	0
Shoreham	1982	123	140	819	0	0
Callaway	1980	128	142	1150	1	0
Maine Yankee	1980	126	141	825	1	0
North Anna 1&2	1980	118	132	850	1	0.5
Sperry 1&2	1980	104	116	775	1	0.5
Wolf Creek	1983	109	122	1150	1	0
Waterford 3	1984	114	123	1114	1	0
Beaver Valley	1984	139	150	833	1	0
Wawaunee	1984	114	123	535	1	0
Davis Besse	1984	138	149	906	1	0
Diablo Canyon 1	1985	215	224	1094	1	1
Diablo Canyon 2	1985	256	266	1106	1	0
Shippingport	1985	98	102	150	1	0
Perry 1	1985	259	269	1205	0	0
Duane Arnold	1985	154	160	538	0	0
River Bend 1	1985	201	209	940	0	0
Crystal River 3	1985	177	184	825	1	0
Nine Mile 2	1986	254	264	1085	0	0
Hoptle 1	1986	215	215	1100	1	0
Hoptle 2	1986	176	176	1100	1	1
Seabrook 1	1986	221	221	1150	1	0
Nine Mile 1	1986	212	212	610	0	0

Notes: [1] From Response to Interrogatory #NMAG-4-23, NMPSC 2004.
[2] Inflated at GNP.
[3] PWR = 1 if PWR.
[4] TWIN = 1 if cheaper twin, .5 if pair of units.

FIGURE 4.4.1

Decommissioning Costs

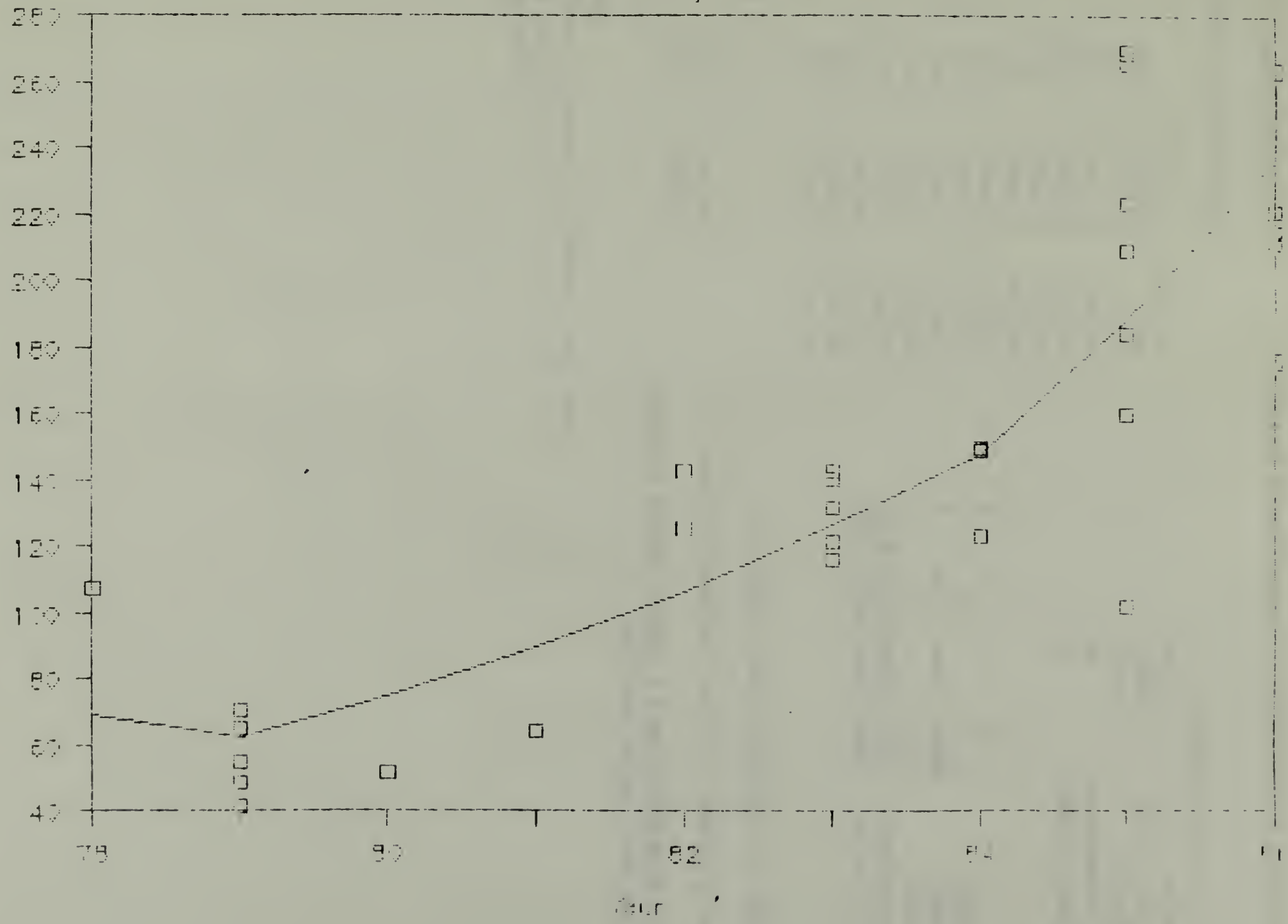


TABLE 4.4.2: REGRESSION RESULTS, TLG DECOMMISSIONING ESTIMATES

Regression Output:

Constant	-11.7049
Std Err of Y Est	0.198324
R Squared	0.871725
No. of Observations	30
Degrees of Freedom	25

Y	b	c	d	f
LN(COST) ($1986)	LN(MW)	Year	PWR	T
=======	------	----	---	-
X Coefficient(s)	0.3409	0.173984	-0.2110	-0.121
Std Err of Coef.	0.0894	0.015074	0.07932	0.1151

LN(COST) = a + b(ln(MW) + c(Year) + d(PWR) + f(T)

Cost = e^a * MW^b * (e^c)^Year * (e^d)^PWR * (e^f)^Twin

Cost = 8.25E-06 * MW^.3409 * 1.19^Year * .7987^PWR * .8917^Twin,
where Year = Base Year minus 1900.

TABLE 4.4.3: REACTOR YEARS OF EXPERIENCE

Retired Units in Order of First Generation:

Unit	Years	1st Electric Generate	Shutdown Date
Dresden 1	18.54	15-Apr-60	31-Oct-78
Indian Point 1	12.12	16-Sep-62	31-Oct-74
Humboldt Bay	13.21	18-Apr-63	02-Jul-76
Hallam	1.26	29-May-63	01-Sep-64
Elk River	4.44	24-Aug-63	01-Feb-68
Piqua	2.16	04-Nov-63	01-Jan-66
[illegible]	3.04	18-Dec-63	01-Jan-67
Bonus	3.8	14-Aug-64	01-Jun-69
Pathfinder	1.19	25-Jul-66	01-Oct-67
Fermi 1	6.32	05-Aug-66	29-Nov-72
Peach Bottom 1	7.76	27-Jan-67	01-Nov-74
Three Mile Island	0.93	21-Apr-78	28-Mar-79

Other Early Units:

Yankee-Rowe	26.62	10-Nov-60
Big Rock Point	24.55	08-Dec-62

Source: NRC Greybook.

[1] Years from first generation to shutdown - longer than commercial life.

[2] To 19-Jun-87 .

TABLE 4.4.4: DECOMMISSIONING PROJECTIONS

Projections:	Optimistic	Improved	Historic
Basis:	BECO Projection	x 2.5	x 4.0
Year	[1]	[2]	[3]
1987	$3,911,250	$9,778,125	$15,645,000
1988	$4,079,434	$10,198,584	$16,317,735
1989	$4,254,849	$10,637,124	$17,019,398
1990	$4,437,808	$11,094,520	$17,751,232
1991	$4,628,634	$11,571,584	$18,514,535
1992	$4,827,665	$12,069,162	$19,310,660
1993	$5,035,255	$12,588,136	$20,141,018
1994	$5,251,770	$13,129,426	$21,007,082
1995	$5,477,597	$13,693,991	$21,910,385
1996	$5,713,133	$14,282,833	$22,852,533
1997	$5,958,798	$14,896,995	$23,835,192
1998	$6,215,026	$15,537,566	$24,860,105
1999	$6,482,272	$16,205,681	$25,929,090
2000	$6,761,010	$16,902,525	$27,044,040
2001	$7,051,734	$17,629,334	$28,206,934
2002	$7,354,958	$18,387,395	$29,419,832
2003	$7,671,221	$19,178,053	$30,684,885
2004	$8,001,064	$20,002,710	$32,004,355
2005	$8,345,130	$20,862,826	$33,380,522
2006	$8,703,971	$21,759,928	$34,815,884
2007	$9,078,242	$22,695,604	$36,312,967
2008	$9,468,606	$23,671,515	$37,874,425

Notes: [1] From 85-27, $5,000,000 in 1986, rising with construction cost inflation of 4.3%.,reduced by 25% to reflect BECO's share of Pilgrim.

[2] Average of Optimistic and Historic.

[3] Column [1] x 4, e.g., doubled for likely increase in decommissioning cost, and doubled again for shorter collection period.

TABLE 4.6: ANALYSIS OF OVERHEAD EXPENSE FOR YANKEE PLANTS ($ THOUSANDS)

	Yankee Atomic		Connecticut Yankee		Vermont Yankee		Maine Yankee		
	1984	1985	1984	1985	1984	1985	1984	1985	
1. Other O&M	2,553	2,871	6,370	6,776	8,777	10,226	17,934	19,289	
2. Employment Taxes:									
FICA	1,462	1,462	686	686	724	724	705	705	
Fed Unemp.	38	38	16	16	45	45	19	19	
State Unemp.	78	78	33	33	48	48	63	63	
3. Total Other	4,131	4,448	7,106	7,512	9,594	11,044	18,722	20,077	
4. Station O&M	38,113	43,895	86,320	86,492	64,652	67,187	67,574	71,454	
5. Fuel	11,691	7,301	26,432	40,941	21,449	20,771	25,079	35,694	
6. Non-fuel Station O&M	26,422	36,595	59,889	45,550	43,203	46,416	32,495	35,760	
7. Other as a % of Non-fuel Station O&M	15.63%	12.16%	11.87%	16.49%	22.21%	23.79%	57.61%	56.14%	Average: 26.99%

Source: 1985 FERC Forms of Yankee Atomic, Maine Yankee, Vermont Yankee, and Connecticut Yankee.

TABLE 4.7.1: BECO'S SHARE OF SUNK COSTS, RETIREMENT IN 2009 - Page 1

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (GWH): 3,054
3. Retirement Date: 2009

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year			152.6	180.7	212.4	244.1	275.8	307.5	339.1	370.8	402.5
8. Annual Depreciation			28.1	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7
9. End of Year		152.6	180.7	212.4	244.1	275.8	307.5	339.1	370.8	402.5	434.2
10. Net-Plant (Year-End)		543.5	665.4	633.7	602.0	570.3	538.6	507.0	475.3	443.6	411.9
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-129.8	-137.9	-143.1	-145.7	-142.7	-139.5
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	0	0	0	0	0	0	0	0
14. Average Rate Base			557.7	541.8	502.6	463.7	425.0	389.4	356.4	329.0	301.9
14A. BECO Portion			418.3	406.4	377.0	347.8	318.8	292.0	267.3	246.7	226.4
Costs											
15. Return on Rate Base			43.2	42.0	39.0	36.0	33.0	30.2	27.6	25.5	23.4
16. Income Taxes			20.5	19.9	18.5	17.0	15.6	14.3	13.1	12.1	11.1
17. Depreciation			21.1	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
18. O&M Expenses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes			8.0	7.6	7.2	6.8	6.5	6.1	5.7	5.3	4.9
21. Decommissioning			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel			37.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost			130.7	93.3	88.4	83.6	78.8	74.4	70.2	66.7	63.2
24. Cents/kwh Rate			4.28	3.06	2.90	2.74	2.58	2.43	2.30	2.18	2.07

TABLE 4.7.1: REVENUE REQUIREMENTS, RETIREMENT IN 2008

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (MW): 3,154
3. Retirement Date: 2008

	Case	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Plant-in-service											
4. Beginning of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year		434.2	465.9	497.6	529.2	560.9	592.6	624.3	656.0	687.7	719.4
8. Annual Depreciation		31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7
9. End of Year		465.9	497.6	529.2	560.9	592.6	624.3	656.0	687.7	719.4	751.0
10. Net-Plant (Year-End)		380.2	348.5	316.9	285.2	253.5	221.8	190.1	158.4	126.7	95.1
Other Rate Base Items											
11. Deferred Taxes		-136.2	-132.9	-125.7	-121.5	-114.9	-105.2	-93.3	-59.6	-36.7	-8.5
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8	48.1
13. Nuclear Fuel		0	0	0	0	0	0	0	0	0	0
14. Average Rate Base		275.0	248.2	225.4	193.6	176.3	156.2	138.4	142.5	135.8	134.7
14A. BECO Portion		206.3	186.2	169.0	149.7	132.2	117.1	103.8	106.9	101.9	101.0
Costs											
15. Return on Rate Base		21.3	19.3	17.5	15.5	13.7	12.1	10.7	11.1	10.5	10.4
16. Income Taxes		10.1	9.1	8.3	7.3	6.5	5.7	5.1	5.2	5.0	4.9
17. Depreciation		23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		4.6	4.2	3.8	3.4	3.0	2.7	2.3	1.9	1.5	1.1
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		59.8	56.3	53.3	50.0	47.0	44.3	41.9	42.0	40.8	40.3
24. Cents/kwh Rate		1.96	1.84	1.75	1.64	1.54	1.45	1.37	1.37	1.34	1.32

TABLE A-7.11: PEDCO# OF SOL[illegible] UNITS, RETIREMENT IN 2008

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (MW): 2,054
3. Retirement Date: 2008

	Case	2006	2007	2008	CNPVRR @ 10.34%	CNPVRR @ 15.00%	CNPVRR @ 20.00%
Plant-in-service							
4. Beginning of Year		846.1	846.1	846.1			
5. Net Additions		0.0	0.0	0.0			
6. End of Year		846.1	846.1	846.1			
Accumulated Depreciation							
7. Beginning of Year		751.0	782.7	814.4			
8. Annual Depreciation		31.7	31.7	31.7			
9. End of Year		782.7	814.4	846.1			
10. Net-Plant (Year-End)		63.4	31.7	0.0			
Other Rate Base Items							
11. Deferred Taxes		25.5	66.3	0			
12. Materials & Supplies		50.5	53.1	42.5			
13. Nuclear Fuel		0	0	0			
14. Average Rate Base		139.4	151.1	42.5			
14A. BECO Portion		104.5	113.3	31.9			
Costs							
15. Return on Rate Base		10.8	11.7	3.3	222.1	180.1	149.2
16. Income Taxes		5.1	5.6	1.6	105.2	85.3	70.7
17. Depreciation		23.8	23.8	23.8	200.7	150.0	116.2
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.1	0.0	0.0
20. Local Taxes		0.8	0.4	0.0	43.0	34.8	28.8
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		40.5	41.4	28.6	571.0	450.3	364.9
24. Cents/kWh Rate		1.32	1.36	0.94			

TABLE 4.7.1: RECOVERY OF SUNK COSTS, RETIREMENT IN 2004

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (GWH): 3,054
3. Retirement Date: 2004

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150	0	0	0	0	0	0	0	0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year			152.6	187.0	225.7	264.5	303.3	342.1	380.8	419.6	458.4
8. Annual Depreciation			34.4	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8
9. End of Year		152.6	187.0	225.7	264.5	303.3	342.1	380.8	419.6	458.4	497.1
10. Net-Plant (Year-End)		543.5	659.1	620.4	581.6	542.8	504.0	465.3	426.5	387.7	349.0
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-137.9	-143.1	-145.7	-142.7	-136.2	-130.9
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	0	0	0	0	0	0	0	0
14. Average Rate Base			551.4	528.5	482.2	428.1	385.2	345.1	310.6	279.6	245.6
14A. BECO Portion			413.6	396.3	361.6	321.1	288.9	258.8	233.0	209.7	184.2
Costs											
15. Return on Rate Base		42.8	41.0	37.4	33.2	29.9	26.8	24.1	21.7	19.0	
16. Income Taxes		20.3	19.4	17.7	15.7	14.2	12.7	11.4	10.3	9.0	
17. Depreciation		25.8	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
20. Local Taxes		7.9	7.4	7.0	6.5	6.0	5.6	5.1	4.7	4.2	
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
22. Fuel		37.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
23. Annual Cost		134.6	96.9	91.2	84.5	79.2	74.1	69.7	65.7	61.2	
24. Cents/kwh Rate		4.41	3.17	2.99	2.77	2.59	2.43	2.28	2.15	2.01	

TABLE 4.7.2: BENEFIT OF SOX [illegible], RETIREMENT IN 2004

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (GWH): 3,054
3. Retirement Date: 2004

	Case	1996	1997	1998	1999	2000	2001	2002	2003	2004	1 [illegible]%
Plant-in-service											
4. Beginning of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	
5. Net Additions		0	0	0	0	0	0	0	0	0	
6. End of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	
Accumulated Depreciation											
7. Beginning of Year		497.1	535.9	574.7	613.5	652.2	691.0	729.8	768.6	807.3	
8. Annual Depreciation		38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	
9. End of Year		535.9	574.7	613.5	652.2	691.0	729.8	768.6	807.3	846.1	
10. Net-Plant (Year-End)		310.2	271.4	232.6	193.9	155.1	116.3	77.5	38.8	0.0	
Other Rate Base Items											
11. Deferred Taxes		-125.7	-121.5	-105.2	-93.3	-59.6	-36.7	25.5	66.3	0	
12. Materials & Supplies		31	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8	
13. Nuclear Fuel		0	0	0	0	0	0	0	0	0	
14. Average Rate Base		215.5	182.5	161.6	136.5	132.2	119.2	144.6	148.8	45.8	
14A. BECO Portion		161.6	136.9	121.2	102.3	99.9	89.4	108.5	111.6	34.4	
Costs											
15. Return on Rate Base		15.7	14.2	12.5	10.6	10.3	9.2	11.2	11.5	3.6	192.5
16. Income Taxes		7.9	6.7	5.9	5.0	4.9	4.4	5.3	5.5	1.7	91.2
17. Depreciation		29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	228.4
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		3.7	3.3	2.8	2.3	1.9	1.4	0.9	0.5	0.2	27.5
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		57.4	53.2	50.3	47.0	46.2	44.1	46.5	46.5	34.3	548.7
24. Cents/kwh Rate		1.88	1.74	1.65	1.54	1.51	1.44	1.52	1.52	1.12	

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (MW): 3,054
3. Retirement Date: 2004

		DNPURR @	DNPURR @
	Case	15.00%	20.00%
Plant-in-service			
4. Beginning of Year			
5. Net Additions			
6. End of Year			
Accumulated Depreciation			
7. Beginning of Year			
8. Annual Depreciation			
9. End of Year			
10. Net-Plant (Year-End)			
Other Rate Base Items			
11. Deferred Taxes			
12. Materials & Supplies			
13. Nuclear Fuel			
14. Average Rate Base			
14A. BECO Portion			
Costs			
15. Return on Rate Base		159.8	134.6
16. Income Taxes		76.1	59.2
17. Depreciation		194.4	157.1
18. O&M Expenses		0.0	0.0
19. Insurance/Overhead		0.0	0.0
20. Local Taxes		31.9	25.3
21. Decommissioning		0.0	0.0
22. Fuel		0.0	0.0
23. Annual Cost		463.0	366.6
24. Cents/kWh Rate			

TABLE 4.7.3: RECOVERY OF SUNK COSTS, RETIREMENT IN 1997

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (MW): 3,054
3. Retirement Date: 1997

	Case	1996	1997	1998	1999	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year			152.6	208.8	272.6	336.3	400.0	463.7	527.5	591.2	654.9
8. Annual Depreciation			56.2	63.7	63.7	63.7	63.7	63.7	63.7	63.7	63.7
9. End of Year		152.6	208.8	272.6	336.3	400.0	463.7	527.5	591.2	654.9	718.6
10. Net-Plant (Year-End)		543.5	637.3	573.5	509.8	446.1	382.4	318.6	254.9	191.2	127.5
Other Rate Base Items											
11. Deferred Taxes			-103.7	-121.5	-143.1	-145.7	-136.2	-129.5	-114.9	-93.3	-66.7
12. Materials & Supplies			20	21	22.1	23.2	24.3	25.5	26.8	28.1	29.5
13. Nuclear Fuel			51	0	0	0	0	0	0	0	0
14. Average Rate Base			529.6	473.0	388.8	323.6	270.5	214.6	166.8	126.0	120.3
14A. BECO Portion			397.2	354.8	291.6	242.7	202.8	161.0	125.1	94.5	90.2
Costs											
15. Return on Rate Base			41.1	36.7	30.2	25.1	21.0	16.6	12.9	9.8	9.3
16. Income Taxes			19.5	17.4	14.3	11.9	9.9	7.9	6.1	4.6	4.4
17. Depreciation			42.2	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8
18. O&M Expenses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes			7.6	6.9	6.1	5.4	4.6	3.8	3.1	2.3	1.5
21. Decommissioning			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel			37.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost			148.3	108.7	98.4	90.1	83.3	76.2	69.9	64.5	63.1
24. Cents/kwh Rate			4.85	3.56	3.22	2.95	2.73	2.49	2.29	2.11	2.07

TABLE 4.7.3: RECOVERY OF SUNK COSTS, RETIREMENT IN 1997

1. Capacity Factor = 70.00%
2. BECO Share of
 Generation (MW) : 3,151
3. Retirement Date: 1997

	Case	1996	1997	CNPVRR @ 10.04%	CNPVRR @ 15.00%	CNPVRR @ 20.00%
Plant-in-service						
4. Beginning of Year		846.1	846.1			
5. Net Additions		0.0	0.0			
6. End of Year		846.1	846.1			
Accumulated Depreciation						
7. Beginning of Year		718.6	782.4			
8. Annual Depreciation		63.7	63.7			
9. End of Year		782.4	846.1			
10. Net-Plant (Year-End)		63.7	0.0			
Other Rate Base Items						
11. Deferred Taxes		25.5	0			
12. Materials & Supplies		31	32.6			
13. Nuclear Fuel		0	0			
14. Average Rate Base		120.2	32.6			
14A. BECO Portion		90.2	24.5			
Costs						
15. Return on Rate Base		9.3	2.5	122.1	107.1	94.3
16. Income Taxes		4.4	1.2	57.3	50.7	44.7
17. Depreciation		47.8	47.8	289.4	239.9	200.4
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0
20. Local Taxes		0.8	0.0	24.5	21.6	19.0
21. Decommissioning		0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0
23. Annual Cost		62.3	51.5	494.0	419.2	358.3
24. Cents/kwh Rate		2.04	1.69			

TABLE 4.8: SUMMARY OF COST INPUTS

	Pilgrim			BECO Share		
	Optimistic	Improved	Historic	Optimistic	Improved	Historic
Capacity Factor	68.4%	62.0%	53.8%	68.4%	62.0%	53.8%
O&M Cost (1988) ($ Million)	$72.7	$78.7	$84.7	$54.5	$59.0	$63.5
O&M Inflation Rate:	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
Incremental Growth (Million 1988$/Year)				$3.30	$3.55	$3.81
Capital Additions (1988) ($ Million)	$18.4	$32.2	$74.7	$13.8	$24.1	$56.0
Capital Additions Inflation Rate	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
Decommissioning (1988) $ (Million)	$5.4	$13.6	$21.8	$4.1	$10.2	$16.3
Decommissioning Inflation Rate:	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%

TABLE 5.1.1: BECO LOAD FORECASTS WITH CONSERVATION PROGRAM

		With Review Panel Adjustments		
	BECO Forecast	Reduction in 1987 Load	Reduction in Growth	Net Load
	[1]	[2]	[3]	[4]
1987	2,588			2,588
1988	2,691	136	51	2,504
1989	2,760	272	88	2,404
1990	2,828	408	120	2,300
1991	2,924	544	168	2,212
1992	2,916	680	164	2,072
1993	2,935	680	174	2,082
1994	2,977	680	195	2,103
1995	2,980	680	196	2,104
1996	2,992	680	202	2,110
1997	3,056	680	234	2,142
1998	3,072	680	242	2,150
1999	3,126	680	269	2,177
2000	3,200	680	306	2,214
2001	3,245	680	329	2,237
2002	3,290	680	351	2,259
2003	3,336	680	374	2,282
2004	3,383	680	398	2,306
2005	3,430	680	421	2,329
2006	3,478	680	445	2,353
2007	3,527	680	470	2,378
2008	3,576	680	494	2,402
2009	3,627	680	520	2,428
2010	3,677	680	545	2,453
2011	3,729	680	571	2,479
2012	3,781	680	597	2,505

[1] 1987-2000 from Boston Edison Load Forecast, January 17, 1988.
2001-2012 from BECO GFRFP.
[2] 136 MW/yr additional, 1988-1992.
[3] .5 x (BECO forecast minus 1987 load).
[4] [1] - [2] - [3].

TABLE 5.1.2: BECO PROJECTED CAPACITY WITHOUT PILGRIM

	Capacity w/o Unit Filing to	Capacity - -	Purchase	Total Available Capacity,
1988	2116	0	454	2570
1987	2116	0	704	2820
1988	2116	0	854	2970
1989	2116	65	854	3035
1990	2116	421	854	3392
1991	2116	597	654	3367
1992	2116	597	304	3017
1993	2116	797	304	3217
1994	2116	797	253	3166
1995	2116	797	253	3166
1996	2116	797	253	3166
1997	2116	797	253	3166
1998	2116	797	236	3149
1999	2116	797	236	3149
2000	2116	797	236	3149
2001	2116	797	236	3149
2002	2116	797	236	3149
2003	2116	797	236	3149
2004	2116	797	236	3149
2005	2116	797	236	3149
2006	2116	797	198	3111
2007	2116	797	198	3111
2008	2116	797	198	3111
2009	2116	774	198	3088
2010	2116	774	198	3088
2011	2116	774	198	3088
2012	2116	774	198	3089

Source: BECO QFRFP, Exhibit 4.

Changes from BECO QFRFP:

[1] 1992 QF capacity additions set at 200 MW, bringing 1991 QF total to 512 MW.

[2] NUGT's added: 150 MW from 1988-90, 50 MW from 1991-1993.

TABLE 5.1.3: LOAD AND CAPACITY COMPARISONS, BECO FORECAST

Year	Projected Capacity	Territory Load	Contract Demand	Total Load	Reserve %	Capability Respons- ibility	Surplus/ Deficit
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1986	2570	2519	30	2549	15.2%	2936	-366
1987	2820	2588	30	2618	16.3%	3045	-225
1988	2970	2691	35	2726	15.4%	3146	-176
1989	3035	2763	35	2798	14.5%	3204	-169
1990	3392	2828	38	2866	16.4%	3336	56
1991	3387	2924	43	2967	16.3%	3451	-84
1992	3017	2916	48	2964	16.3%	3447	-430
1993	3217	2935	53	2988	16.2%	3472	-255
1994	3166	2977	56	3033	16.2%	3524	-358
1995	3166	2980	60	3040	16.2%	3532	-366
1996	3166	2992	60	3052	16.2%	3546	-380
1997	3166	3056	60	3116	16.1%	3618	-452
1998	3149	3072	60	3132	16.1%	3636	-487
1999	3149	3126	60	3186	16.0%	3696	-547
2000	3149	3200	60	3260	16.0%	3782	-633
2001	3149	3245	60	3305	15.9%	3830	-681
2002	3149	3290	60	3350	15.9%	3883	-734
2003	3149	3336	60	3396	15.9%	3936	-787
2004	3149	3383	60	3443	15.8%	3987	-838
2005	3149	3430	60	3490	15.8%	4041	-892
2006	3111	3478	60	3538	15.5%	4086	-975
2007	3111	3527	60	3587	15.5%	4143	-1032
2008	3111	3576	60	3636	15.5%	4200	-1089
2009	3088	3627	60	3687	15.4%	4255	-1167
2010	3088	3677	60	3737	15.4%	4312	-1224
2011	3088	3729	60	3789	15.4%	4373	-1285
2012	3088	3781	60	3841	15.3%	4429	-1341

[1] From Table 5.1.2.
[2],[3],[5] From BECO QFRFP.
[4] Column [2] + Column [3].
[6] Column [4] ÷ Column [5] + Column [4].
[7] Column [1] minus Column [6].

TABLE 5.1.4: LOAD AND CAPACITY COMPARISONS, 'REVIEW PANEL' FORECAST

Year	Projected Capacity	Territory Load	Contract Demand	Total Load	Peserve %	Capacility Respons- ibility	Surplus/ Deficit
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1986	2570	2519	30	2549	15.2%	2936	-366
1987	2820	2588	30	2618	16.3%	3045	-225
1988	2970	2504	35	2539	15.4%	2929	41
1989	3035	2404	35	2439	14.5%	2792	243
1990	3392	2300	38	2338	16.4%	2721	671
1991	3367	2212	43	2255	16.3%	2623	744
1992	3017	2072	48	2120	16.3%	2466	551
1993	3217	2092	53	2135	16.2%	2480	737
1994	3166	2103	56	2159	16.2%	2508	658
1995	3166	2104	60	2164	16.2%	2515	651
1996	3166	2110	60	2170	16.2%	2522	644
1997	3166	2142	60	2202	16.1%	2557	609
1998	3149	2150	60	2210	16.1%	2566	583
1999	3149	2177	60	2237	16.0%	2595	554
2000	3149	2214	60	2274	16.0%	2638	511
2001	3149	2237	60	2297	15.9%	2662	487
2002	3149	2259	60	2319	15.9%	2688	461
2003	3149	2282	60	2342	15.9%	2714	435
2004	3149	2306	60	2366	15.8%	2739	410
2005	3149	2329	60	2389	15.8%	2766	383
2006	3111	2353	60	2413	15.5%	2787	324
2007	3111	2378	60	2438	15.5%	2815	296
2008	3111	2402	60	2462	15.5%	2844	267
2009	3088	2428	60	2488	15.4%	2871	217
2010	3088	2453	60	2513	15.4%	2899	189
2011	3088	2479	60	2539	15.4%	2929	159
2012	3088	2505	60	2565	15.3%	2957	131

Notes: [1] From Table 5.1.2.
[2] From Table 5.1.1.
[3],[5] From BECO QFRFP.
[4] Column [2] + Column [3].
[6] Column [4] x Column [5] + Column [4].
[7] Column [1] minus Column [6].

TABLE 5.1.5: LOAD AND CAPABILITY COMPARISONS, INTERMEDIATE FORECAST

Year	Projected Capacity	Capability Respons-ibility	Surplus/ Deficit
		[6]	[7]
1985	2570	2936	-366
1987	2820	3045	-225
1989	2970	3038	-68
1989	3035	2998	37
1990	3392	3029	363
1991	3367	3037	330
1992	3017	2956	61
1993	3217	2976	241
1994	3166	3016	150
1995	3166	3024	142
1996	3165	3034	132
1997	3166	3087	79
1998	3149	3101	48
1999	3149	3145	4
2000	3149	3210	-61
2001	3149	3246	-97
2002	3149	3285	-136
2003	3149	3325	-176
2004	3149	3363	-214
2005	3149	3404	-255
2006	3111	3437	-326
2007	3111	3479	-368
2008	3111	3522	-411
2009	3088	3563	-475
2010	3088	3606	-518
2011	3088	3651	-563
2012	3088	3693	-605

[1] From Table 5.1.3.
[2] Average of Colum [5] in Tables 5.1.3. and 5.1.4.
[7] Colum [1] minus Colum [2].

TABLE 5.1.4: REPLACEMENT CAPACITY COSTS, "PEAK"

Year	Capacity Cost $ kW [1]	Cumulative MW Needed [2]	Total Capacity Cost ($ Thousand) [3]	O&M $/kW [4]	Total O&M ($ Thousand) [5]	Total Cost ($ Thousand) [6]
1988	$40.70	176	$7,154	$1.61	$283	$7,438
1989	$42.45	169	$7,161	$1.70	$287	$7,448
1990	$44.27	0	$0	$1.79	$0	$0
1991	$46.17	84	$3,861	$1.89	$158	$4,019
1992	$48.16	430	$20,715	$1.99	$856	$21,571
1993	$50.23	255	$12,812	$2.10	$535	$13,347
1994	$52.39	358	$18,774	$2.21	$792	$19,566
1995	$54.64	366	$20,026	$2.33	$854	$20,880
1996	$56.99	390	$21,682	$2.46	$934	$22,616
1997	$59.44	452	$26,849	$2.59	$1,169	$28,018
1998	$62.00	487	$30,210	$2.73	$1,329	$31,539
1999	$64.67	493	$32,204	$2.88	$1,432	$33,636
2000	$67.45	498	$33,598	$3.03	$1,509	$35,098
2001	$70.35	498	$35,033	$3.19	$1,591	$36,624
2002	$73.37	499	$36,539	$3.37	$1,677	$38,216
2003	$76.53	498	$38,110	$3.55	$1,767	$39,878
2004	$79.82	499	$39,749	$3.74	$1,863	$41,612
2005	$83.25	496	$41,458	$3.94	$1,963	$43,422
2006	$86.83	498	$43,241	$4.16	$2,069	$45,310
2007	$90.56	496	$45,100	$4.38	$2,181	$47,282
2008	$94.46	498	$47,040	$4.62	$2,299	$49,339

Notes: [1] From BECo OR RFP, page c-27.
[2] From Table 5.1.3.
[3] Column [2] x Column [1].
[4] BECo OR RFP, page c-27.
[5] Column [2] x Column [4].
[6] Column [5] + Column [3].

TABLE 5.2.2: REPLACEMENT CAPACITY COSTS, INTERMEDIATE FORECAST

Year	Capacity Cost $ /kw [1]	Cumulative MW Needed [2]	Total Capacity Cost ($ Thousand) [3]	O&M $/kw [4]	Total O&M ($ Thousand) [5]	Total Cost ($ Thousand) [6]
t						
1988						
1989						
1990						
1991	$46.17					
1992	$48.16					
1993	$50.23					
1994	$52.39					
1995	$54.64					
1996	$56.99					
1997	$59.44					
1998	$62.00					
1999	$64.67					
2000	$67.45	61	$4,095	$3.03	$184	$4,279
2001	$70.35	97	$6,829	$3.19	$310	$7,139
2002	$73.37	136	$9,992	$3.37	$459	$10,451
2003	$76.53	176	$13,482	$3.55	$625	$14,107
2004	$79.82	214	$17,091	$3.74	$801	$17,892
2005	$83.25	255	$21,224	$3.94	$1,005	$22,229
2006	$86.83	326	$28,281	$4.16	$1,353	$29,634
2007	$90.56	368	$33,341	$4.38	$1,612	$34,953
2008	$94.46	411	$38,784	$4.62	$1,895	$40,679

Notes: [1] From BECo QR RFP, page c-27.
[2] From Table 5.1.5.
[3] Column [2] x Column [1].
[4] BECo QF RFP, page c-27.
[5] Column [2] x Column [4].
[6] Column [5] + Column [3].

TABLE S.I.1: COMPARISON OF ENERGY SUPPLIES

	Minimum Energy Contribution					Increment						
	QFs		Pilgrim		Total	QFs		Pilgrim		Total	Maximum Energy	Increment
Case [1]	MW	GWH	CF	GWH	GWH	MW	GWH	CF	GWH	GWH	GWH	GWH
AC1	192	1,346	54%	2,356	3,701	200	1,402		0	1,402	5,103	4,4??
AC2	192	1,346	70%	3,054	4,399	200	1,402		0	1,402	5,801	5,100
AC3	393	2,754	35%	1,527	4,281	200	1,402		0	1,402	5,683	4,982
AC4	393	2,754	70%	3,054	5,808	200	1,402		0	1,402	7,209	6,509
PR1	512	3,588		0	3,588		0	54%	2,356	2,356	5,944	4,788
PR2	512	3,588		0	3,588		0	70%	3,054	3,054	6,642	5,115

Notes: [1] AC1=Pilgrim at 54% CF and 192 MW of QF, AC2= Pilgrim at 70% CF and 192 MW of QF, AC3= Pilgrim at 35% CF and 393 MW of QF, AC4= Pilgrim at 70% CF and 393 MW of QF, PR1 and PR2 = no Pilgrim capacity and 512 MW of QF.

[2], [5] QF's always have 80% capacity factor. GWH = MW x 80% x 8760 /1000.

[3], [6] Pilgrim is 498 MW. GWH = 498 x CF x 8760/1000.

[4] Column [2] + Column [3].

[7] Column [5] + Column [6].

[8] Column [4] + Column [7].

FIGURE 5.3.1:

COMPARISON OF ENERGY SUPPLIES

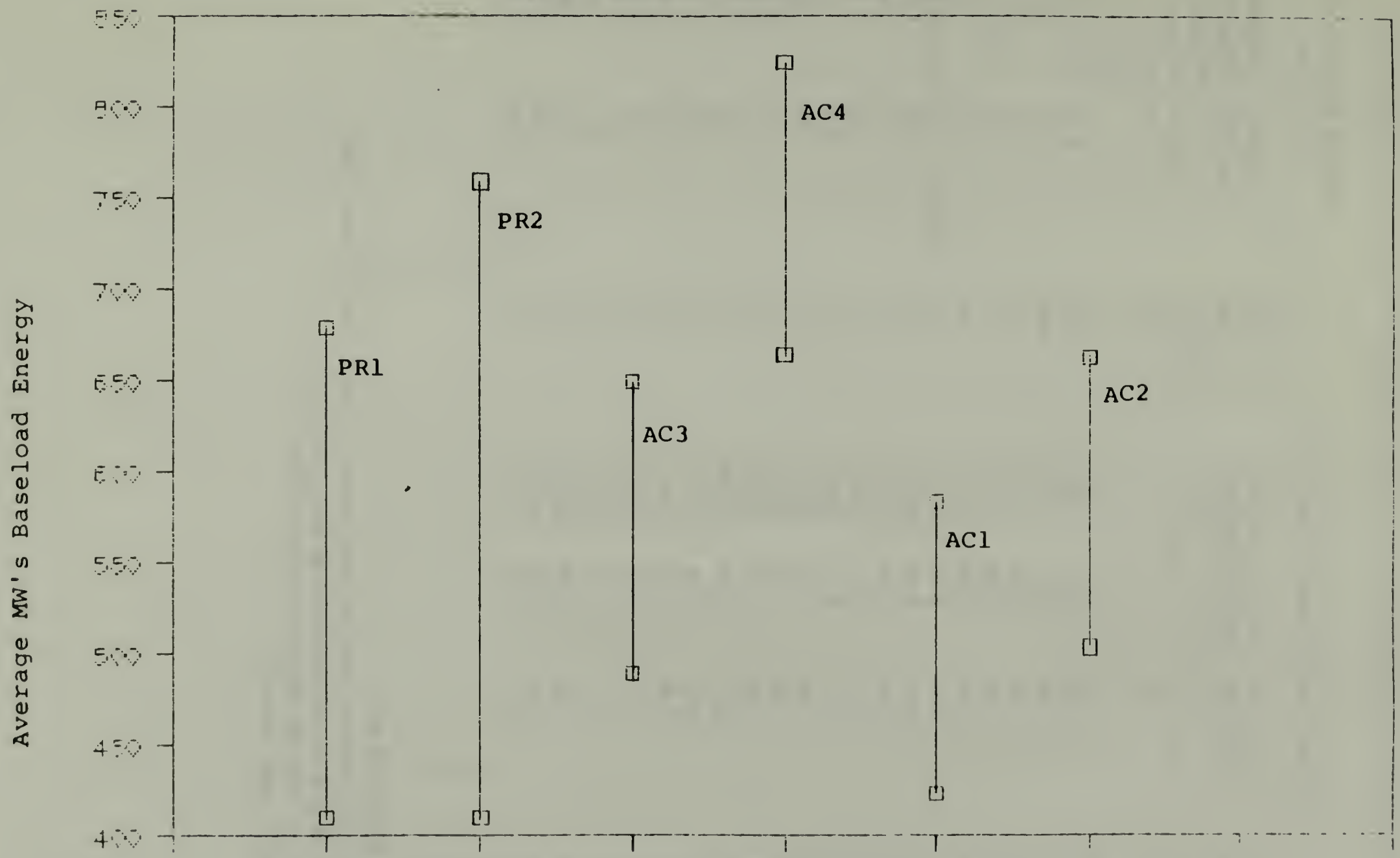


TABLE 5.3.2: BECO AVOIDED COST PROJECTIONS ADJUSTED BY RATIO OF CURRENT DRI FORECASTS TO JULY, 1988 FORECAST

		Replacement Costs Adjusted for Fuel Costs:				Adjusted Replacement Costs net of Pilgrim Fuel:		
Year	BECO Avoided Costs	Winter 1986/1987 (Low)	Winter 1986/1987 (Reference)	Winter 1986/1987 (High)	Pilgrim Fuel Costs (cents/kwh)	Winter 1986/1987 (Low)	Winter 1986/1987 (Reference)	Winter 1986/1987 (High)
	[1]	[2]			[3]	[4]		
1987	3.05	1.34	3.10	5.05	0.57	0.77	2.54	4.48
1988	3.12	1.28	3.17	5.06	0.60	0.69	2.57	4.46
1989	3.26	1.42	3.26	5.25	0.63	0.80	2.63	4.62
1990	3.39	1.64	3.39	5.57	0.67	0.98	2.72	4.90
1991	3.89	1.93	3.89	6.73	0.70	1.23	3.18	6.03
1992	4.94	2.44	4.94	9.26	0.74	1.70	4.20	8.51
1993	5.57	2.99	5.57	11.61	0.78	2.21	4.79	10.83
1994	6.2	3.16	6.20	13.30	0.83	2.37	5.37	12.48
1995	6.86	3.48	6.86	15.14	0.87	2.61	5.98	14.28
1996	7.71	3.97	7.71	16.94	0.92	3.05	6.79	16.02
1997	8.76	4.85	9.76	18.80	0.97	3.88	7.78	17.82
1998	9.69	4.48	9.68	20.10	1.03	3.45	8.65	19.07
1999	11.21	4.88	11.21	21.84	1.09	3.79	10.12	20.76
2000	12.43	5.30	12.43	23.03	1.15	4.16	11.28	21.88
2001	13.71	5.77	13.70	24.87	1.21	4.56	12.49	23.66
2002	15.49	6.63	15.48	27.27	1.28	5.35	14.20	25.99
2003	16.49	6.88	16.48	28.49	1.35	5.53	15.13	27.14
2004	18.26	7.75	18.26	30.35	1.43	6.32	16.80	28.64
2005	20.29	8.41	20.28	32.90	1.51	6.91	18.77	31.39
2006	22.17	9.31	22.16	35.34	1.59	7.71	20.57	33.75
2007	23.49	10.30	23.48	36.90	1.68	8.62	21.80	35.22
2008	25.34	11.50	25.33	39.79	1.78	9.72	23.55	38.01
2009	27.08	12.97	27.07	42.70	1.88	10.99	25.19	40.82
2010	28.77							
2011	31.31							
2012	33.63							

Notes: [1] From BECO revised RFP.
[2] Column [1] * ratio of current DRI price forecasts to DRI forecasts of Summer, 1988.
[3] From 2/88 EFSC Forecast. Multiplied by average heat rate of
Pilgrim 1 from 1980-1985, and divided by 10,000.
[4] Column [2] minus Column [3].

TABLE 5.D.1. NEW BOSTON HEAT RATES

Year	Heat Rate
1981	9,611
1982	9,520
1983	9,583
1984	9,502
1985	9,891
Average	9621.6

Source: Boston Edison FERC Form 1. 1981-1985.

TABLE 5.3.4: PILGRIM REPLACEMENT POWER COSTS BASED ON DRI OIL PRICE FORECASTS & NEW BOSTON HEAT RATES

						Net Replacement Costs		
Year	Winter 1986/1987 (Low) Cents/kwh	Winter 1986/1987 (Reference) Cents/kwh	Winter 1986/1987 (High) Cents/kwh	Pilgrim Fuel Cost $/mmBtu	Pilgrim Fuel Cost Cents/kwh	Winter 1986/1987 (Low) Cents/kwh	Winter 1986/1987 (Reference) Cents/kwh	Winter 1986/1987 (High) Cents/kwh
	[1]			[2]	[3]	[4]		
1987	1.02	2.35	3.83	$0.542	0.57	0.45	1.79	3.26
1988	1.03	2.55	4.07	$0.572	0.60	0.44	1.95	3.47
1989	1.19	2.72	4.38	$0.604	0.63	0.56	2.09	3.75
1990	1.43	2.94	4.83	$0.638	0.67	0.76	2.27	4.16
1991	1.61	3.23	5.60	$0.674	0.70	0.90	2.53	4.89
1992	1.74	3.53	6.62	$0.711	0.74	1.00	2.79	5.87
1993	2.05	3.82	7.97	$0.751	0.78	1.27	3.04	7.19
1994	2.20	4.26	9.15	$0.793	0.83	1.37	3.44	8.32
1995	2.43	4.78	10.54	$0.838	0.87	1.55	3.90	9.67
1996	2.76	5.37	11.79	$0.884	0.92	1.84	4.44	10.87
1997	3.03	6.10	13.10	$0.934	0.97	2.06	5.13	12.12
1998	3.23	6.98	14.51	$0.986	1.03	2.20	5.95	13.48
1999	3.49	8.01	15.62	$1.042	1.09	2.40	6.92	14.53
2000	3.92	9.19	17.03	$1.100	1.15	2.77	8.04	15.88
2001	4.33	10.29	18.67	$1.162	1.21	3.12	9.08	17.46
2002	4.94	11.54	20.32	$1.227	1.28	3.66	10.26	19.05
2003	5.31	12.72	21.98	$1.296	1.35	3.96	11.36	20.62
2004	5.99	14.11	23.47	$1.369	1.43	4.56	12.68	22.05
2005	6.46	15.58	25.28	$1.446	1.51	4.96	14.07	23.77
2006	7.13	16.98	27.08	$1.527	1.59	5.54	15.39	25.48
2007	8.06	18.38	28.88	$1.613	1.68	6.38	16.69	27.19
2008	8.91	19.62	30.83	$1.703	1.78	7.13	17.85	29.05
2009	9.92	20.87	32.93	$1.799	1.88	8.04	19.00	31.05

Notes: [1] DRI Forecast from Docket # DPU 86-280, Q-AG-JWN-82.
Price for 1% S Oil in cents/mmBTU.
Multiplied by 9622.6, the average heat rate for New Boston from 1981-1985, and divided by 1,000,000.
[2] From 2/86 EFSC Forecast. Extrapolated after 2000 with the average growth rate from 1996 to 2000.
[3] Column [2] * 10,430, the average heat rate for Pilgrim from 1980-1985, divided by 10,000.
[4] Column [1] minus Column [3].

TABLE 6.11 CAPACITY FACTORS FOR LOW-PERFORMANCE PLANTS

	San Onofre 1	Palisades	Beaver Valley 1	Oyster Creek
69	31.9%			
69	66.1%			
70	77.6%			
71	63.8%			
72	71.1%	24.5%		
73	57.5%	33.5%		
74	79.8%	1.1%		64.5%
75	80.3%	33.8%		55.2%
76	62.6%	39.5%		67.6%
77	59.2%	70.7%	39.8%	57.0%
78	66.0%	36.5%	33.2%	64.0%
79	85.1%	47.7%	23.8%	80.0%
80	20.7%	33.0%	4.0%	34.3%
81	19.3%	48.2%	62.5%	46.2%
82	12.9%	46.5%	36.0%	35.4%
83	-0.3%	52.4%	63.7%	3.6%
84	6.7%	11.3%	63.6%	4.9%
85	62.4%	73.7%	79.1%	65.8%
86	9.7%	11.7%	48.4%	22.9%

Source: Licenced Operating Reactors, NRC, 1969 through 1986.

APPENDIX 1:

Letter from Carl Gustin, BECO

BOSTON EDISON
Executive Offices
800 Boylston Street
Boston, Massachusetts 02199

June 8, 1987

Carl Gustin
Vice President
Corporate Relations

The Honorable Sharon M. Pollard
Secretary of Energy Resources
Commonwealth of Massachusetts
100 Cambridge Street - Room 1500
Boston, MA 02202

Dear Secretary Pollard:

This responds to your May 8 letter to Steve Sweeney requesting data on Pilgrim Station costs.

As I mentioned to Mary Beth Gentleman last week on the telephone, I am sorry we could not respond in the ten days you requested, but it did take longer than that to develop the specific information.

In reviewing the information, please note that the forecasted data pertains to the entire Pilgrim I unit, not just the Boston Edison Company share. Also, the company has applied to the NRC for an extension of its operating license to the year 2012 and has, therefore, used that retirement date in the forecast.

In this response, we have provided a reasonable estimate of Pilgrim's costs for the next 25 years. However, as you know, many factors external to the company, such as NRC mandated modifications, can significantly impact Pilgrim's costs. With that in mind, we are presenting the data to you in two ways.

Exhibit 1 presents the forecast as you requested it for 1987 through the year 2012 using a cost-of-service format.

Exhibit 2 is a comparison of forecasted incremental costs of Pilgrim and the available alternatives. Exhibit 2 presents the data from the most realistic and comprehensive economic perspective. It places the future costs of Pilgrim in context with the future costs of available alternatives in the event Pilgrim's capacity had to be replaced. The alternatives, presented on a bus bar basis, include the six cogeneration.

small power producer and third party contracts that the company has already signed, results of the qualifying facility bid and four new construction options. The new construction options are combustion turbine, combined cycle, integrated gasification combined cycle and a pulverized coal unit. Levelized costs from 1980 through 2008 are also included.

It does not include conservation and load management because the company's resource plan already includes 500 megawatts for conservation, load management and time of use rates and the company is pursuing every option to expand that potential.

This analysis shows that the future costs of Pilgrim are lower than any other options throughout the period.

A second key point emerges from this analysis and a review of the company's resource plan which has been provided to you. To use 670 MW of alternate sources to replace Pilgrim would, in effect, foreclose important future options for either meeting growth, or reducing demand or replacing aging capacity. Therefore, from the standpoint of cost, reliability and supply diversity, electricity users clearly benefit from the return to service of Pilgrim I and its operation at a 70 percent or higher capacity factor.

I hope this is responsive to your request. Please let me know if you would like additional information or would like to discuss the data.

Sincerely,

Carl Gustin
Vice President
Corporate Relations

Enclosures (2)

cc: Chairman Paul F. Levy
Mass. Dept. of Public Utilities

RESPONSE		1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	PLANT-IN-SERVICE																			
	BEGINNING OF YEAR		696.1	846.1	886.1	926.1	996.1	1036.1	1078.1	1122.2	1168.5	1217.1	1268.2	1321.8	1378.1	1437.2	1499.2	1564.4	1632.8	1704.6
1(c)	NET ADDITIONS		150.0	40.0	40.0	70.0	40.0	42.0	44.1	46.3	48.6	51.1	53.6	56.3	59.1	62.1	65.2	68.4	71.8	75.4
	END OF YEAR	696.1	846.1	886.1	926.1	996.1	1036.1	1078.1	1122.2	1168.5	1217.1	1268.2	1321.8	1378.1	1437.2	1499.2	1564.4	1632.8	1704.6	1780.0
	ACCUMULATED DEPRECIATION																			
	BEGINNING OF YEAR		152.6	176.4	204.0	233.2	264.9	299.0	335.1	373.4	414.0	457.3	503.5	552.9	606.1	663.3	725.2	792.5	865.7	946.0
	ANNUAL DEPRECIATION		23.8	27.6	29.3	31.6	34.1	36.1	38.3	40.6	43.3	46.2	49.5	53.1	57.3	61.9	67.2	73.3	80.3	88.5
3	END OF YEAR	152.6	176.4	204.0	233.2	264.9	299.0	335.1	373.4	414.0	457.3	503.5	552.9	606.1	663.3	725.2	792.5	865.7	946.0	1034.5
	NET PLANT (YEAR-END)	543.5	669.7	682.1	692.9	731.2	737.1	743.0	748.8	754.5	759.9	764.7	768.8	772.0	773.8	774.0	771.9	767.0	758.6	745.5
	OTHER RATE BASE ITEMS																			
2(b)	DEFERRED TAXES		-103.7	-112.9	-121.5	-129.8	-137.9	-143.1	-147.1	-145.7	-142.7	-139.5	-136.2	-132.9	-129.5	-125.7	-121.5	-114.9	-105.2	-93.3
	MATERIALS & SUPPLIES		20.0	21.0	22.1	23.2	24.3	25.5	26.8	28.1	29.5	31.0	32.6	34.2	35.9	37.7	39.6	41.6	43.7	45.8
	NUCLEAR FUEL		51.0	51.0	50.0	50.0	50.2	50.2	54.4	56.4	60.2	66.1	67.2	75.4	75.4	84.2	84.2	92.2	93.9	99.3
1	AVERAGE RATE BASE (1/2 ADDITIONS)		562.0	621.3	623.4	639.6	653.7	654.6	660.9	670.2	682.6	696.9	705.6	720.5	726.1	739.2	741.6	751.7	755.0	759.7

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	COSTS																			
2(a)	RETURN ON RATE BASE	58.1	64.2	64.4	66.1	67.5	67.6	68.3	69.3	70.5	72.0	72.9	74.5	75.0	76.4	76.6	77.7	78.0	78.5	
2(b)	INCOME TAXES	27.5	30.3	30.5	31.2	31.9	32.0	32.3	32.7	33.3	34.0	34.5	35.2	35.5	36.1	36.2	36.7	36.9	37.1	
1(a)	DEPRECIATION (1/2 YEAR CONVENTION - REMAINING LIFE)	23.8	27.6	29.3	31.6	34.1	36.1	38.3	40.6	43.3	46.2	49.5	53.1	57.3	61.9	67.2	73.3	80.3	88.5	
1(b)	O & M EXPENSES	96.5	99.0	106.5	119.5	125.0	131.3	137.8	144.7	151.9	159.5	167.5	175.9	184.7	193.9	203.6	213.8	224.5	235.7	
1(g)	INSURANCE	4.5	4.7	5.0	5.2	5.5	5.7	6.0	6.3	6.6	7.0	7.3	7.7	8.1	8.5	8.9	9.4	9.8	10.3	
1(b)	LOCAL TAXES	10.7	10.9	11.1	11.7	11.8	11.9	12.0	12.1	12.2	12.2	12.3	12.4	12.4	12.4	12.4	12.3	12.1	11.9	
1(d)	DECOMMISSIONING ANNUAL CONTRIBUTION	4.2	4.5	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3	8.8	9.4	10.0	10.7	11.4	12.1	
1(a)	FUEL	5.4	26.9	23.8	23.8	23.8	23.8	25.8	26.8	28.6	31.4	31.9	35.8	35.8	40.8	40.0	43.8	44.6	47.2	
	ANNUAL COST	230.6	268.2	275.2	294.2	305.1	314.2	326.6	339.0	353.3	369.7	383.7	402.8	417.5	438.6	455.0	477.6	497.6	521.4	
	GENERATION (GWH)		4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	
	CENTS/KWH RATE		6.53	6.70	7.16	7.43	7.65	7.95	8.25	8.60	9.00	9.34	9.80	10.16	10.67	11.07	11.62	12.11	12.69	

RESPONSE		2005	2006	2007	2008	2009	2010	2011	2012
	PLANT-IN-SERVICE								
	BEGINNING OF YEAR	1780.0	1859.2	1942.4	2029.7	2099.6	2155.4	2200.2	2235.9
1(c)	NET ADDITIONS	79.2	83.2	87.3	69.9	55.9	44.7	35.8	28.6
	END OF YEAR	1859.2	1942.4	2029.7	2099.6	2155.4	2200.2	2235.9	2264.5
	ACCUMULATED DEPRECIATION								
	BEGINNING OF YEAR	1034.5	1132.7	1242.4	1366.3	1506.0	1661.4	1833.5	2025.8
	ANNUAL DEPRECIATION	98.1	109.7	123.9	139.7	155.4	172.1	192.3	238.8
3	END OF YEAR	1132.7	1242.4	1366.3	1506.0	1661.4	1833.5	2025.8	2264.5
	NET PLANT (YEAR-END)	726.6	700.0	663.4	593.6	494.1	366.6	210.1	0.0
	OTHER RATE BASE ITEMS								
2(b)	DEFERRED TAXES	-78.3	-59.6	-36.7	-8.5	25.5	66.3	115.5	0.0
	MATERIALS & SUPPLIES	40.1	50.5	53.1	42.5	34.0	27.2	21.7	17.4
	NUCLEAR FUEL	105.1	111.3	117.9	124.9	93.6	62.4	31.2	0.0
	AVERAGE RATE BASE (1/2 ADDITIONS)	762.0	760.7	754.0	717.4	619.3	500.2	360.7	3.1
	COSTS								
2(a)	RETURN ON RATE BASE	78.7	78.6	77.9	74.1	64.0	51.7	37.3	0.3
2(b)	INCOME TAXES	37.2	37.2	36.8	35.0	30.2	24.4	17.6	0.2
1(e)	DEPRECIATION (1/2 YEAR CONVENTION -	98.1	109.7	123.9	139.7	155.4	172.1	192.3	238.8
1(b)	O & M EXPENSES	247.5	259.9	272.9	286.5	300.8	315.9	331.7	348.2
1(g)	INSURANCE	10.8	11.4	11.9	12.5	13.2	13.8	14.5	15.2
1(h)	LOCAL TAXES	11.6	11.2	10.6	9.5	7.9	5.9	3.4	0.0
1(d)	DECOMMISSIONING ANNUAL CONTRIBUTION	13.0	13.9	14.9	16.0	17.2	18.7	20.7	10.8
1(a)	FUEL	49.9	52.9	56.0	59.3	62.8	66.6	70.6	74.9
	ANNUAL COST	547.0	574.7	605.0	632.7	651.6	669.2	688.0	688.4
	GENERATION (GWH)	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4	4108.4
	CENTS/KWH RATE	13.31	13.99	14.73	15.40	15.86	16.29	16.75	16.76

This exhibit compares the incremental cost of Pilgrim 1 generation with that of alternative sources. Page 2 is a table showing the forecasted annual busbar costs of each alternative and page 3 shows the costs of several alternatives graphically.

The abbreviations used in this exhibit are as follows:

INCR PIL	- Incremental Cost of Pilgrim 1 Generation
PEAT	- Peat Products
EVRT EN	- Everett Energy
TD	- TD Energy
NEA	- Northeast Energy Associates
PRS	- Power Recovery Systems
OSP	- Ocean State Power
AVG	- Average cost of the non utility contracts
RFP	- Request For Proposal Prices adjusted for capacity charge in years 1988 - 1991
CT	- Combustion Turbine Unit
CC	- Combined Cycle Unit
IGCC	- Integrated Gasification Combined Cycle Unit
PC	- Pulverized Coal Unit
PIL-EXH1	- Pilgrim Costs From Exhibit 1

BOSTON EDISON COMPANY

BUSBAR COMPARISON

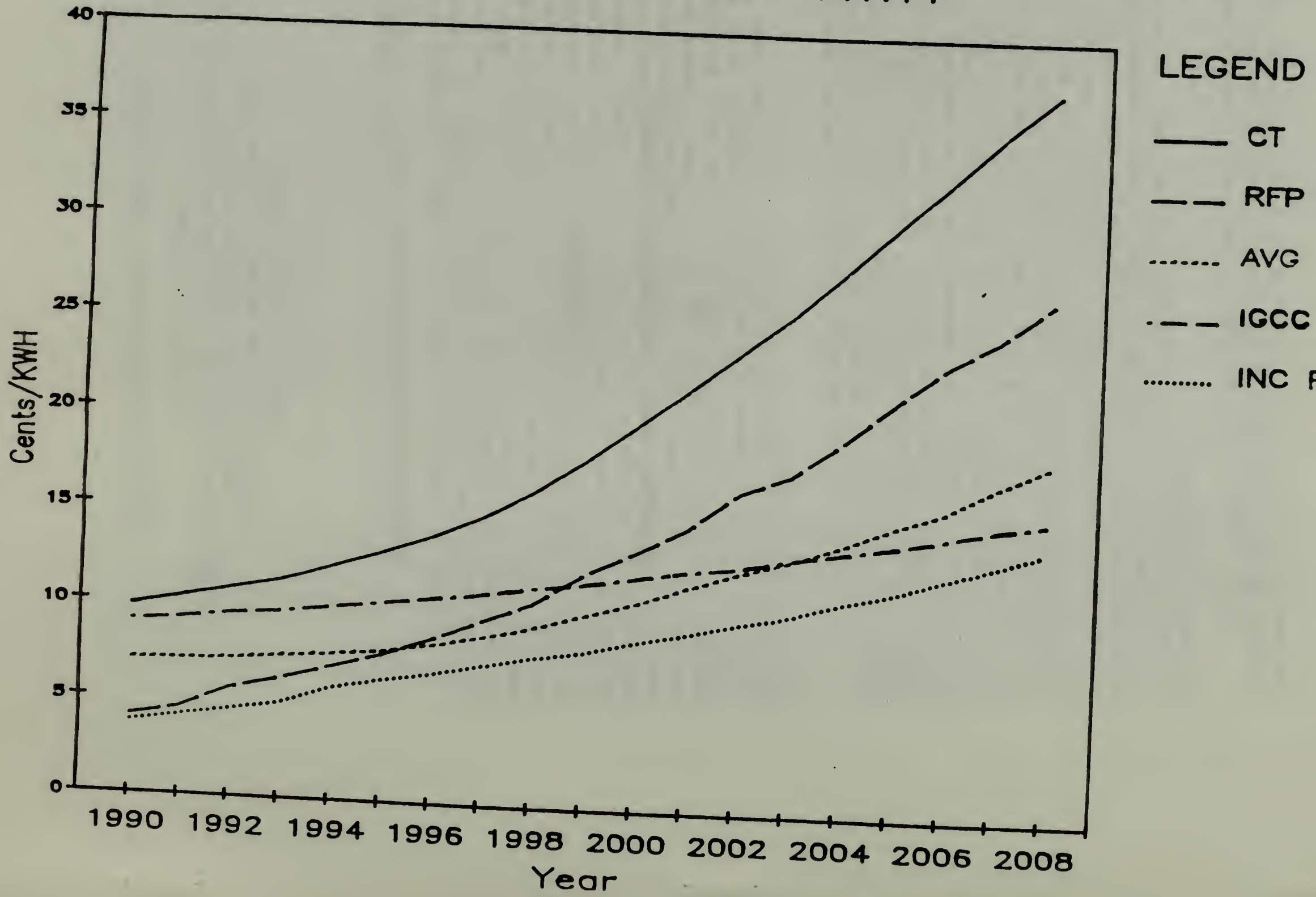
CENTS PER KWH

	INCR. PIL.	NEP AVOIDED COSTS	NON-UTILITY CONTRACTS							CONSTRUCTION OPTIONS				* PIL. (EXH.1)
			PEAT	EVRT.EN.	TB	NEA	PRS	DSP	AVG	CT	CC	IGCC	PC	
1988	2.2	3.7			7.3				7.3					6.5
1989	3.1	3.8	7.6	6.7	7.3	6.5	6.5		6.7					6.7
1990	3.7	4.0	7.7	7.0	7.3	6.5	6.6	7.4	7.0	9.8	6.5	9.0	10.0	7.2
1991	4.1	4.5	7.8	7.3	7.3	6.5	6.8	7.5	7.1	10.3	6.9	9.2	10.3	7.4
1992	4.5	5.6	7.9	7.6	7.3	6.5	7.0	7.6	7.2	10.8	7.2	9.5	10.6	7.7
1993	4.9	6.2	8.0	7.9	7.3	6.5	7.2	7.7	7.4	11.3	7.6	9.7	10.8	8.0
1994	5.9	6.9	8.1	8.3	7.3	6.5	7.4	8.0	7.6	12.1	8.1	10.0	11.2	8.3
1995	6.3	7.6	8.2	8.7	7.3	6.5	7.6	8.3	7.8	12.9	8.6	10.3	11.5	8.6
1996	6.8	8.5	8.4	9.1	7.3	6.9	7.8	8.7	8.2	13.8	9.3	10.6	11.8	9.0
1997	7.2	9.5	8.5	9.6	7.3	7.8	8.0	9.1	8.7	14.9	10.1	10.9	12.2	9.3
1998	7.7	10.5	8.7	10.1	7.3	8.6	8.3	9.8	9.3	16.3	11.0	11.3	12.5	9.8
1999	8.1	12.1	8.8	10.6	7.3	9.8	8.5	10.3	10.0	18.0	12.2	11.6	12.9	10.2
2000	8.7	13.3	9.0	11.2	7.3	10.8	8.7	11.2	10.7	19.9	13.6	12.0	13.3	10.7
2001	9.2	14.6	9.1	11.8	7.3	12.6	8.9	11.7	11.6	21.8	14.9	12.4	13.7	11.1
2002	9.8	16.5	9.3	12.4	7.3	14.1	9.0	12.2	12.4	23.8	16.4	12.7	14.1	11.6
2003	10.3	17.5	9.5	13.1	15.9	15.0	9.2	12.8	13.1	25.8	17.7	13.2	14.6	12.1
2004	11.0	19.3	9.6	13.8	17.5	16.6	9.3	13.5	14.0	28.1	19.4	13.6	15.1	12.7
2005	11.6	21.4	9.8	14.6	19.4	18.3	9.5	14.2	15.0	30.5	21.1	14.0	15.6	13.3
2006	12.4	23.3	10.0	15.4	20.0	20.0	9.7	15.1	15.9	32.8	22.7	14.5	16.0	14.0
2007	13.2	24.7	10.2	16.3	21.2	22.3	9.9	16.0	17.2	35.2	24.3	15.0	16.6	14.7
2008	13.9	26.6	10.4	17.2	22.8	24.1	10.1	17.1	18.3	37.3	25.8	15.4	17.1	15.4
2009	14.4	28.4		18.2	24.3	25.7	10.2	18.2	20.0	39.4	27.3	15.9	17.7	15.9
2010	14.8	30.1		19.3	25.8	27.3	10.4		22.3					16.3
YEARS 1990 THROUGH 2008														
NPV	55.0	79.5	68.4	77.6	72.2	75.0	63.3	76.6	74.9	129.6	87.9	87.5	97.4	75.3
LEV	6.8	9.8	8.5	9.6	9.0	9.3	7.8	9.5	9.3	16.1	10.9	10.8	12.1	9.3
1990 DOLLARS @	10.55%													

* THIS COLUMN DOES NOT REPRESENT INCREMENTAL COSTS AND HENCE IS NOT COMPARABLE TO THE OTHER COLUMNS IN THE TABLE.

EXHIBIT 2
(Page 3 of 3)

BUSBAR COMPARISON
CENTS PER KWH



APPENDIX 2:

"Depreciating Nuclear Power Plants"

DEPRECIATING NUCLEAR POWER PLANTS

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I. Introduction and Statement of the Problem

Most U.S. electric utilities with operating nuclear power plants are currently under-recovering in their rates for nuclear decommissioning expense and for nuclear plant depreciation. This results from two separate, but interactive, mis-estimates. First, most owner/operators use optimistic estimates of total decommissioning expense (i.e., of net negative salvage value), which causes decommissioning expense provisions in depreciation expenses, and thus total depreciation accruals, to be too low. Second, most owner/operators use optimistic estimates of total (and remaining) useful service lives, which causes depreciation rates, expenses, and total accruals to be two low. These two practices in turn cause electric utilities with nuclear power plants to have current rates, gross revenues, net income, and internally-generated cash flows that are lower than they would be otherwise.

Electric utilities have tended to use decommissioning expense estimates of roughly $75 M - $150 M (in 1986 $), or about $75 to $150 per KW (in 1986 $) for a 1000 MW unit. These traditional estimates have been based upon early engineering cost estimate studies. Similarly, electric utilities have tended to use assumptions for nuclear power plants' useful service lives of 38-40 years, which were in turn taken from assumptions used in NRC licensing cases. Electric utilities were not averse to using optimistic decommissioning expense estimates and optimistic useful service life estimates in general, because the primary initial use of these estimates was in proceedings designed to justify nuclear power plant construction, such as NRC licensing proceedings, state certification of need proceedings, or state proceedings to determine the prudence of generation planning decisions.

This paper looks at likely decommissioning expense estimates in Section II and at likely useful service life estimates in Section III. Limitations and warnings are stated

in Section IV. Conclusions are stated in Section V. In general, it is concluded that (unless there are overwhelming concerns about loss of load due to price elasticity effects) most U.S. electric utilities with nuclear power plants should raise their provisions in rates for nuclear decommissioning expenses and for nuclear depreciation expenses. References are listed in Section VI and the data base for Section III is listed in summary form in Appendix A.

II. Decommissioning Expense Amount

Traditional engineering cost estimates have been produced for several U.S. commercial nuclear power plants. In addition, Battelle Pacific Northwest has produced two widely cited decommissioning cost estimates for the NRC for a reference PWR (ref. (1)) and for a reference BWR (ref. (2)). These two studies produced cost estimates (in 1978 $) for the reference plants as shown below in Table 1.

Table 1: Battelle Pacific Northwest
Decommissioning Cost Estimates

1155 MW BWR, immediate dismantlement	$43.6M
1155 MW BWR, storage & deferred dismantlement	$58.8M
1155 MW BWR, entombment	$40.6M
1175 MW PWR, immediate dismantlement	$42.1M
1175 MW PWR, storage & deferred dismantlement	$46.8M-$51.8M

Let us focus on the immediate dismantlement alternative because that appears to be the NRC-favored alternative. The $43.6M and the $42.1M estimates (in 1978 $) are roughly equivalent to estimates of $69M and $66M, respectively, in 1986 $, using a GNP deflator of 1.575. More recent estimates by owner/operators for specific plants have generally tended to cluster around the range of $110M to $130M in 1986 $ for a nuclear plant in the 1,000 MW to 1,150 MW size range.

Despite these relatively optimistic decommissioning cost estimates, there is substantial reason to believe that the actual decommissioning costs will be higher by a factor of about two to five in constant dollar terms. Estimates of past error rates in U.S. commercial nuclear power plant construction cost estimates are about 10% per year above inflation. Applying these past error rates to decommissioning projects that will occur twenty years or more in the future implies (if no moderation occurs) that current estimates are low by a factor of at least five. If one assumes that past error rates in commercial nuclear power plant construction cost estimates (which were remarkably persistent over a per-

iod of at least twenty years) would moderate in the future for decommissioning cost estimates, then current decommissioning cost estimates might nevertheless be low by a factor of two in constant dollar terms. It must be emphasized that decommissioning cost estimates have already begun to show the same persistent and robust growth in constant dollar terms that construction cost estimates have shown in the past. See ref. (3), pp. 110-123, and ref. (4).

In sum, the current plant-specific decommissioning cost estimates, which tend to cluster around and slightly above $100 per KW in 1986 $, are probably best viewed as being too low by a factor of two to five in constant dollar terms. For financial planning purposes, electric utilities with nuclear power plants should probably use decommissioning cost estimates in the range of $200 to $500 per KW in 1986 $.

III. Depreciation Rate: Useful Service Life

In order to produce a depreciation reserve that matches tangible property's original cost at the time of that property's retirement, one needs an accurate before-the-fact estimate of the property's useful service life. This section of this paper describes an attempt to estimate (on a before-the-fact basis) the expected useful service life of a U.S. LWR, based upon actual experience to date. The purpose of this exercise is to determine whether or not the relatively arbitrary assumptions about useful service lives that are currently in widespread use are consistent with actual data.

A. The Data Sets

Three data sets of U.S. light water reactors were constructed. For all three data sets, no distinction was made between PWRs and BWRs. For all three data sets, other types of technologies were excluded: breeders, gas-cooled, and graphite-moderated reactors, for example, were excluded. This decision excluded such commercial U.S. reactors as Fort St. Vrain, Peach Bottom 1, and Fermi 1 from this analysis.

Having made the decision to focus on all U.S. LWRs, two further definitions were made. First, a distinction was made between reactors that were "commercial in intent" and reactors which were "non-commercial in intent." "Commercial in intent" was defined to include reactors which were intended to be dispatched commercially for a substantial amount of time, whether or not the reactor was also intended to serve certain research goals. "Non-commercial in intent" was defined to include those reactors which were intended primarily or exclusively to serve research goals. Second, a distinc-

tion was drawn between reactors which were "commercial in design" and those which were "non-commercial in design." "Commercial in design" was defined as including all LWRs over 400 MW, while "non-commercial in design" was defined as including all LWRs under 400 MW.

The first, and least inclusive, data set, Data Set 1, was comprised of all U.S. LWRs which had entered commercial operation before December 31, 1985 and which were both "commercial in intent" and "commercial in design." Data Set 1 included 88 units, with the oldest (San Onofre 1) having entered commercial operation in 7/67 and the newest (Diablo Canyon 2) having entered commercial operation in 10/85. Only one of the 88 units in Data Set 1 was considered to have completed its useful service life for the purposes of this study: Three Mile Island 2, which entered commercial operation in 4/78 and which ceased commercial operation in 3/79.

The second data set, Data Set 2, includes all 88 units in Data Set 1, and additionally includes all 6 U.S. LWRs which were "commercial in intent" but "non-commercial in design." Data Set 2 thus included 94 units, with the six additions to Data Set 1 being Dresden 1, Yankee Rowe, Indian Point 1, Big Rock Point, Humboldt Bay, and LaCrosse. Three of these six additional units (Dresden 1, Indian Point 1, and Humboldt Bay) have been retired.

The third data set, Data Set 3, is the most inclusive. It includes all 94 units in Data Set 2, and additionally includes all four U.S. LWRs that were "non-commercial in intent" as well as "non-commercial in design." These four additional units were Shippingport, Elk River, BONUS, and Pathfinder. All four of these additional units are retired.

These three data sets are summarized in Table 2, below.

Table 2: Data Set Summary

Data Set	Includes All U.S. LWRs Which Were		LWRs in Data Set	LWRs Retired
	Design	Intent		
Data Set 1	Commercial	Commercial	88	1
Data Set 2	Commercial or Non-Comm.	Commercial	94	4
Data Set 3	Commercial or Non-Comm.	Commercial or Non-Comm.	98	8

B. Results

Analyzing the three data sets produces some evidence that useful service lives are likely (but not certain) to be shorter than the currently-assumed 38-40 year useful service lives. This is the result, whether one uses such traditional depreciation rate calculation methods as Iowa curves (refs. (5), (6), and (7)) or more modern statistical methods as product-limit estimates or reduced-set estimates (ref. (8), ch. 4). For the three defined data sets, and for the two estimation methods applied to estimate useful service lives, Table 3 below shows the estimates which seem most consistent with the data.

Table 3: Useful Service Life Estimates

Data Set	Product-Limit Estimate	Reduced-Set Estimate
Data Set 1	25 years or more	25 years or more
Data Set 2	25 - 35 years	20 - 30 years
Data Set 3	20 - 30 years	20 - 30 years

Two points should be made here. First, the data is very sparse. Differences in the estimates between the data sets (holding the estimation method constant) and between the estimation methods (holding the data sets constant) may only reflect random events, and not any real underlying phenomenon. Second, one pattern that appears to emerge in the data is that the less inclusive data sets produce more optimistic estimates than the more inclusive data sets. For example, Data Set 1 is clearly consistent with 40 year lives while Data Sets 2 and 3 do not appear to be consistent with 40 year lives. Whether this is an artifact in the data sets (the oldest unit in Data Set 1 is 19.1 years old) or a real phenomenon (truly commercial units, having somewhat different designs and greater economic value, may be less subject to obsolescence) is not clear at this point.

What is clear is that the data is currently providing weak indications that somewhat shorter useful service lives than the arbitrary 38-40 year assumptions may be appropriate for financial reporting and ratemaking purposes.

IV. CAVEATS

Before stating any conclusions, five caveats seem important.

First, both decommissioning expense amounts and useful service lives are heavily dependent upon NRC regulation. Actions by the NRC to change worker radiation exposure limits (for example) would cause major changes in decommissioning costs. Similarly, actions by the NRC to change "backfitting" requirements (and thus to change one major cause of capital additions) would cause changes in useful service lives by changing the pressures of economic obsolescence, all other things being equal.

Second, useful service lives are heavily dependent upon oil prices and other fossil fuel prices. Economic obsolescence, and hence retirements, are more likely sooner in a world of continued low oil prices and other fossil fuel prices than in a world that reverts to high oil and other fossil fuel prices, all other things being equal.

Third, the data is very sparse to date, and inferences which can be drawn from the data are consequently also weak, in the area of useful service lives. Sparse data only permit relatively weak inferences, with relatively wide confidence intervals. Similarly, the sparseness of the data means that a small amount of future data may modify the best current estimates substantially. A few years of additional experience with no additional retirements will cause best estimates of useful service lives to increase substantially. Similarly, a few retirements in the near future will cause best estimates of useful service lives to decrease substantially.

Fourth, with respect to estimation methods used for estimating decommissioning expense amounts, the estimation methods themselves are somewhat suspect. The traditional engineering cost estimate method, which estimates material and labor quantities from engineering drawings, multiplies them by material and labor cost rates, respectively, and then adds a nominal contingency amount, has proved to be persistently biased on the low side when applied to commercial nuclear power plant construction cost estimation. Whether the traditional engineering cost estimate methodology will prove to be similarly biased when applied to nuclear decommissioning projects is somewhat problematic. However, there are early indications over the past eight years that a similar phenomenon is occurring with respect to decommissioning cost estimates. Applying past error rates of traditional engineering cost estimates (ref. (3), pp. 110-123; ref. (4)) to current engineering cost estimates provides one reasonable sensitivity test that may well prove prophetic. Nevertheless, the models themselves in this area are all necessarily quite weak.

Fifth, all considerations of decommissioning expense amount estimation and of useful service life estimation must be tempered by considerations relating to the total delivered price of electricity before they are adopted in rates. Financial stability considerations argue strongly against undersetimating decommissioning expense or overestimating useful service lives in rates. However, at some point, competitive pressures from near-substitutes for electricity (oil, natural gas, conservation and load management, etc.) dictate that financial considerations be tempered with loss of load and loss of sales considerations. Utilities that are particularly vulnerable to losing industrial load, for example, may wish to underestimate nuclear depreciation expenses in rates for the time being. If this is the case, however, this should be done only after a conscious decision is made, and continued scrutiny should be exercised so that the decision is explicitly reviewed periodically.

V. Conclusions

There is some reason to believe that current nuclear decommissioning cost estimates and current nuclear useful service life estimates are too optimistic. The evidence for this is weak, and the inferences that are properly drawn from the experience to date are similarly weak. Nevertheless, prudent financial planning would seem to require that some upwards revisions in rates be made now to decommissioning cost and depreciation rate provisions. Additionally, owner/operators of nuclear power plants should subject the relevant data to serious scrutiny over the next few years to determine if the current "early warning indications" are in fact borne out by subsequent experience.

VI. References

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Appendix A: The Data Sets and Results

Data Set 1
Product-Limit Estimates

Years of Service	Surviving %
0.0-0.8	100.0%
0.9-19.1	98.9%
over 19.1	no data

Data Set 2
Product-Limit Estimates

Years of Service	Surviving %
0.0-0.8	100.0%
0.9-12.0	98.9%
12.1-13.2	96.5%
13.3-18.3	92.8%
18.5-25.7	74.2%
over 25.7	no data

Data Set 3
Product-Limit Estimates

Years of Service	Surviving %
0.0-0.8	100.0%
0.9-1.1	99.0%
1.3-3.7	97.9%
3.8-3.9	96.7%
4.5-12.0	95.4%
12.1-13.2	93.2%
13.3-18.3	89.7%
18.5-23.7	74.8%
25.3-25.7	37.4%
over 25.7	no data

Data Set 1
Reduced-Set Estimates

Years of Service	Surviving %
0.0-0.7	100%
0.9-8.3	98%
8.4-19.0	100%
over 19.0	no data

Data Set 2
Reduced-Set Estimates

Years of Service	Surviving %
0.0-0.7	100%
0.9-8.3	98%
8.4-11.9	100%
12.1-12.6	97%
12.8-13.2	96%
13.3-13.7	92%
13.8-13.9	91%
14.0-14.2	90%
14.3	89%
14.6-15.0	88%
15.3	87%
15.7	86%
15.8	84%
16.3	83%
16.6	81%
16.7	80%
16.8	77%
18.3	75%
18.5	62%
18.9	57%
19.0	50%
23.3	40%
23.6	50%
23.8	33%
25.7	50%
26.3	0%
over 26.3	no data

Data Set 3
Reduced-Set Estimates

Years of Service	Surviving %
0.0-0.7	100%
0.9-1.2	98%
1.3-3.7	97%
3.8	96%
4.5	95%
4.6-8.3	94%
8.4-10.2	95%
10.3-11.8	94%
11.9	93%
12.1	91%
12.2-12.6	90%
12.8	89%
12.9-13.1	88%
13.2	87%
13.3-13.7	83%
13.8	82%
13.9	81%
14.0	80%
14.2	79%
14.3	78%
14.6	77%
15.0	76%
15.3	75%
15.7	73%
15.8	70%
16.3	68%
16.6	66%
16.7	64%
16.8	61%
18.3	58%
18.5	53%
18.9	45%
19.0	40%
20.0	33%
21.9	37%
22.9	42%
23.3	50%
23.6	60%
23.8-25.3	50%
25.7	33%
26.3	0%
29.4	50%
over 29.4	no data

APPENDIX 3:

Supply Situations For Other Major Pilgrim Participants

TABLE A3-4: COMPARISON OF AVOIDED ENERGY COSTS

	BECO [1]	Montaup [2]	Commonwealth Electric [3]
1987	3.05	2.97	3.38
1988	3.13	2.71	3.43
1989	3.26	2.67	3.46
1990	3.39	2.66	3.72
1991	3.89	2.85	4.05
1992	4.94	3.27	4.45
1993	5.57	3.70	4.91
1994	6.20	4.21	5.41
1995	6.95	4.67	6.01
1996	7.71	5.13	6.69
1997	8.76	5.82	7.46
1998	9.68	6.17	8.43
1999	11.21	7.26	9.56
2000	12.43	7.47	10.85
2001	13.71	8.43	12.19
2002	15.49	9.38	13.58
2003	16.49	10.81	14.96
2004	18.36	11.87	16.43
2005	20.29	13.22	18.22
2006	22.17	14.72	19.88
2007	23.49	14.87	
2008	25.34		
2009	27.08		

Notes: [1] From BECO revised RFP.
[2] Eastern Edison Company, QF RFP, Long-run Ceiling Price Schedules, Text, Assumptions, and Worksheets, January 15, 1987, Table 3.
[3] Commonwealth Electric Company, RFP, April, 1987.

TABLE 48-B: COMPARISON OF AVOIDED CAPACITY COSTS

	Boston Edison [1]		Montaup [2]		Commonwealth Electric [3]	
	$/KW	Cents/KWH	$/KW	Cents/KWH	$/KW	Cents/KWH
1988						
1989						
1990						
1991	$46.17	0.61			$39.40	0.52
1992	$48.18	0.64			$41.68	0.55
1993	$50.23	0.66			$43.95	0.58
1994	$52.39	0.69	$59.10	0.78	$46.22	0.61
1995	$54.64	0.72	$62.13	0.82	$48.50	0.64
1996	$56.96	0.75	$65.17	0.86	$51.53	0.68
1997	$59.44	0.78	$66.95	0.81	$55.02	0.70
1998	$62.00	0.82	$73.74	0.96	$58.10	0.78
1999	$64.67	0.85	$76.53	1.01	$62.89	0.83
2000	$67.45	0.89	$81.08	1.07	$67.44	0.89
2001	$70.35	0.93	$84.87	1.12	$71.99	0.95
2002	$73.37	0.97	$89.41	1.18	$76.53	1.01
2003	$76.53	1.01	$94.72	1.25	$82.59	1.09
2004	$79.82	1.05	$100.02	1.32	$87.90	1.16
2005	$83.25	1.10	$105.33	1.39	$93.20	1.23
2006	$86.83	1.15	$110.63	1.46	$99.26	1.31
2007	$90.56	1.20	$116.69	1.54		
2008	$94.46	1.25				

Notes: [1] From BECO QF RFP, page c-27.
[2] From Eastern Edison Company, RFP, Long-run Ceiling Price Schedule, Text, Assumptions, and Worksheets, January 15, 1987, Table 3.
[3] Commonwealth Electric Company, RFP, April, 1987.

TABLE AC-1: PROJECTED CAPACITY WITHOUT PILGRIM

	Commonwealth Electric [1]			Montaup Electric Company [2]		
	Capacity without Pilgrim	Capacity +/-	Total Available Capacity	Capacity Without Pilgrim	Capacity +/-	Total Available Capacity
1987	761	85	846	573	232	805
1988	761	85	846	573	236	809
1989	761	105	866	573	243	816
1990	761	131	892	573	317	890
1991	761	141	902	573	366	939
1992	761	166	927	573	395	968
1993	761	176	937	573	380	953
1994	761	176	937	573	380	953
1995	761	186	947	573	380	953
1996	761	186	947	573	376	949
1997	761	186	947	573	361	934
1998	761	186	947	573	361	934
1999	761	186	947	573	361	934
2000	761	186	947	573	361	934
2001	761	186	947	572	361	933
2002	761	186	947	572	361	933
2003	761	186	947	572	361	933
2004	761	186	947	572	361	933
2005	761	186	947	572	361	933
2006	761	186	947	572	361	933
2007	761	186	947	572	361	933
2008	761	186	947			
2009	761	186	947			

Notes: [1] From Decision of SFSC No. 86-4, p 13. Pilgrim, Seabrook and Gas Turbines were eliminated, and Hydro Quebec Phase II was extended to 2009.
[2] From OFSFP Filing, 1/15/87, Exhibit 1. 29 MW added in 1992. Pilgrim, Seabrook, and Combustion Turbines were eliminated.

TABLE A3-C: LOAD AND CAPACITY COMPARISONS

Commonwealth Electric

Year	Projected Capacity	Territory Load	Contract Demand	Total Load	ESCC Capability, Reserve %	ESCC Capability, Responsibility	ESCC Surplus/ Deficit	Canal Electric Capability, Reserve %	Canal Electric Capability, Responsibility	Canal Surplus/ Deficit
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1986										
1987	848	787	0	787	16.0%	915	-68	21.0%	952	-105
1988	848	810	0	810	15.4%	935	-88	21.0%	980	-132
1989	856	831	0	831	14.5%	951	-95	21.0%	1006	-150
1990	852	848	0	848	15.4%	987	-95	21.0%	1026	-174
1991	912	862	0	862	16.0%	1003	-100	21.0%	1043	-141
1992	927	877	0	877	16.3%	1020	-93	23.0%	1070	-143
1993	937	892	0	891	16.2%	1037	-99	23.0%	1087	-150
1994	937	905	0	905	16.2%	1052	-114	24.0%	1122	-185
1995	947	917	0	917	16.2%	1065	-118	25.0%	1148	-199
1996	947	930	0	930	16.2%	1081	-133	25.0%	1163	-215
1997	947	941	0	941	16.1%	1092	-145	25.0%	1178	-229
1998	947	952	0	952	16.1%	1105	-156	25.0%	1190	-240
1999	947	964	0	964	16.0%	1118	-171	25.0%	1205	-255
2000	947	979	0	979	16.0%	1133	-186	25.0%	1224	-276
2001	947	994	0	994	15.9%	1152	-205	25.0%	1243	-295
2002	947	1009	0	1009	15.9%	1169	-222	25.0%	1261	-314
2003	947	1024	0	1024	15.9%	1187	-240	25.0%	1280	-333
2004	947	1039	0	1039	15.8%	1203	-256	25.0%	1299	-351
2005	947	1055	0	1055	15.8%	1222	-274	25.0%	1319	-371
2006	947	1071	0	1071	15.5%	1237	-290	25.0%	1339	-391
2007	947	1087	0	1087	15.5%	1255	-308	25.0%	1359	-411
2008	947	1103	0	1103	15.5%	1274	-327	25.0%	1379	-431
2009	947	1120	0	1120	15.4%	1292	-345	25.0%	1400	-453
2010										
2011										
2012										

Notes: [1] From Table A3-C.
[2], [3] From Commonwealth Electric Company, RFP, April, 1987.

TABLE A3-E: LOAD AND CAPACITY COMPARISONS

Year	Projected Capacity	Territory Load	Contract Demand	Total Load	BECO Capability, Reserve %	BECO Capability, Response-bility	Surplus/ Deficit	Montaup Capability, Reserve %	Montaup Capability, Response-bility	Surplus/ Deficit
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1986										
1987	805	764	0	764	16.3%	889	-59	12.0%	856	-91
1988	809	757	0	757	15.4%	874	-64	20.3%	911	-102
1989	816	777	0	777	14.5%	890	-73	15.7%	899	-90
1990	890	797	0	797	16.4%	928	-37	13.9%	908	-18
1991	939	819	0	819	16.3%	952	-13	20.0%	950	-44
1992	968	841	0	841	16.3%	978	-10	20.0%	1009	-41
1993	953	861	0	861	16.2%	1000	-47	19.7%	1031	-78
1994	953	889	0	889	16.2%	1033	-80	20.0%	1067	-114
1995	953	917	0	917	16.2%	1066	-112	20.0%	1100	-147
1996	949	919	0	919	16.2%	1068	-119	20.0%	1103	-154
1997	934	964	0	964	16.1%	1119	-185	20.0%	1157	-223
1998	934	991	0	991	16.1%	1151	-216	20.0%	1189	-255
1999	934	1020	0	1020	16.0%	1183	-249	20.0%	1224	-290
2000	934	1046	0	1046	16.0%	1213	-279	20.0%	1255	-321
2001	930	1067	0	1067	15.9%	1237	-308	20.0%	1290	-347
2002	933	1089	0	1089	15.9%	1262	-329	20.0%	1307	-374
2003	933	1110	0	1110	15.9%	1285	-353	20.0%	1332	-399
2004	933	1133	0	1133	15.8%	1312	-379	20.0%	1360	-427
2005	933	1155	0	1155	15.8%	1337	-404	20.0%	1386	-453
2006	933	1178	0	1178	15.5%	1361	-427	19.8%	1411	-478
2007	933	1202	0	1202	15.5%	1388	-455	20.0%	1442	-509
2008										
2009										

Notes: [1] From Table A3-C.
[2], [8] From Eastern Edison Company, RFP, January 15, 1987.

TABLE A3-F: COMMONWEALTH ELECTRIC COMPANY DEFERRED CAPACITY COSTS

Year	Capacity Cost $/kW	Cumulative MW Needed	Total Capacity Cost ($ Thousand)
	[1]	[2]	[3]
1987	$21.78	74	$1,052
1988	$33.54	74	$2,482
1989	$25.39	74	$1,819
1990	$27.34	74	$1,762
1991	$39.4.	74	$2,918
1992	$41.66	74	$3,084
1993	$43.95	74	$3,252
1994	$46.22	74	$3,420
1995	$48.50	74	$3,589
1996	$51.53	74	$3,813
1997	$53.33	74	$4,030
1998	$59.19	74	$4,374
1999	$62.89	74	$4,654
2000	$67.44	74	$4,990
2001	$71.99	74	$5,327
2002	$78.53	74	$5,663
2003	$83.59	74	$6,112
2004	$87.94	74	$6,504
2005	$93.20	74	$6,897
2006	$99.26	74	$7,346
2007	$105.24	74	$7,789
2008	$111.58	74	$8,257

Notes: [1] From Table A3-B.
[2] From Table A3-D.
[3] Column [1] + Column [2].

TABLE A2-6: MONTAUP COMPANY REPLACEMENT CAPACITY COSTS

Year	Capacity Cost $/kw	Cumulative MW Needed	Total Capacity Cost ($ Thousand)
t	[1]	[2]	[3]
1987	$44.07	51	$2,234
1988	$45.48	74	$3,366
1989	$46.94	74	$3,473
1990	$48.44	18	$857
1991	$50.91	44	$2,225
1992	$53.51	41	$2,178
1993	$56.24	74	$4,161
1994	$59.10	74	$4,374
1995	$62.13	74	$4,598
1996	$65.17	74	$4,822
1997	$68.95	74	$5,103
1998	$72.74	74	$5,383
1999	$76.53	74	$5,663
2000	$81.09	74	$6,000
2001	$84.87	74	$6,280
2002	$89.41	74	$6,617
2003	$94.72	74	$7,009
2004	$100.02	74	$7,402
2005	$105.33	74	$7,794
2006	$110.63	74	$8,187
2007	$116.69	74	$8,635
2008	$122.99	74	$9,102

Notes: [1] From Table A3-B.
[2] From Table A3-E.
[3] Column [1] + Column [2].

APPENDIX 4:

Calculation of Present Value of Capital Cost Recovery

TABLE 44-A: REDWEED OF SUN COSTS, USEFUL LIFE OF 38 YEARS

1. Capacity Factor
2. BECO Share of
 Generation (GWH): 0
3. Retirement Date: 2008

	Case	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year			152.6	180.7	212.4	244.1	275.8	307.5	339.1	370.8	402.5
8. Annual Depreciation			28.1	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7
9. End of Year		152.6	180.7	212.4	244.1	275.8	307.5	339.1	370.8	402.5	434.3
10. Net-Plant (Year-End)		543.5	665.4	633.7	602.0	570.3	538.6	507.0	475.3	443.6	411.8
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-129.8	-137.9	-143.1	-145.7	-142.7	-139.5
12. Materials & Supplies			20	0	0	0	0	0	0	0	0
13. Nuclear Fuel			51	0	0	0	0	0	0	0	0
14. Average Rate Base			557.7	520.8	480.5	440.5	400.7	363.9	329.6	300.9	272.4
14A. BECO Portion			418.3	390.6	360.4	330.4	300.6	272.9	247.2	225.7	204.3
Costs											
15. Return on Rate Base		43.2	40.4	37.3	34.2	31.1	28.2	25.6	23.3	21.1	
16. Income Taxes		20.5	19.1	17.7	16.2	14.7	13.4	12.1	11.1	10.0	
17. Depreciation		21.1	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	
18. O&M Expenses		-3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
19. Insurance/Overhead		-0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
20. Local Taxes		8.0	7.6	7.2	6.8	6.5	6.1	5.7	5.3	4.9	
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
23. Annual Cost		88.8	90.9	85.9	81.0	76.0	71.4	67.1	63.5	59.8	
24. Cents/kwh Rate											

1. Capacity Factor
2. BECO Share of
 Generation (GWh): 0
3. Retirement Date: 2018

	Case	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Plant-in-service											
4. Beginning of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year		434.2	465.9	497.6	529.2	560.9	592.6	624.3	656.0	687.7	719.4
8. Annual Depreciation		31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7
9. End of Year		465.9	497.6	529.2	560.9	592.6	624.3	656.0	687.7	719.4	751.1
10. Net-Plant (Year-End)		380.2	348.5	316.9	285.2	253.5	221.8	190.1	158.4	126.7	95.1
Other Rate Base Items											
11. Deferred Taxes		-136.2	-132.9	-125.7	-121.5	-114.9	-105.2	-93.3	-59.6	-36.7	-8.5
12. Materials & Supplies		0	0	0	0	0	0	0	0	0	0
13. Nuclear Fuel		0	0	0	0	0	0	0	0	0	0
14. Average Rate Base		244.0	215.6	191.2	163.7	138.6	116.6	96.8	98.8	90.0	86.6
14A. BECO Portion		183.0	161.7	143.4	122.7	103.9	87.4	72.6	74.1	67.5	64.9
Costs											
15. Return on Rate Base		18.9	16.7	14.8	12.7	10.7	9.0	7.5	7.7	7.0	6.7
16. Income Taxes		9.0	7.9	7.0	6.0	5.1	4.3	3.6	3.6	3.3	3.2
17. Depreciation		23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		4.6	4.2	3.8	3.4	3.0	2.7	2.3	1.9	1.5	1.1
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		56.2	52.6	49.4	45.9	42.6	39.8	37.1	37.0	35.6	34.8

24. Cents/kWh Rate

1. Capacity Factor
2. BECO Share of
 Generation (GWH): 0
3. Retirement Date: 2008

	Case	2006	2007	2008	CNPVRR @ 10.34%	CNPVRR @ 15.00%	CNPVRR @ 21.00%
Plant-in-service							
4. Beginning of Year		846.1	846.1	846.1			
5. Net Additions		0.0	0.0	0.0			
6. End of Year		846.1	846.1	846.1			
Accumulated Depreciation							
7. Beginning of Year		751.0	782.7	814.4			
8. Annual Depreciation		31.7	31.7	31.7			
9. End of Year		782.7	814.4	846.1			
10. Net-Plant (Year-End)		63.4	31.7	0.0			
Other Rate Base Items							
11. Deferred Taxes		25.5	66.3	0			
12. Materials & Supplies		0	0	0			
13. Nuclear Fuel		0	0	0			
14. Average Rate Base		88.9	98.0	0.0			
14A. BECO Portion		66.7	73.5	0.0			
Costs							
15. Return on Rate Base		6.9	7.6	0.0	202.5	166.3	139.0
16. Income Taxes		3.3	3.6	0.0	96.0	78.8	65.9
17. Depreciation		23.8	23.8	23.8	200.7	150.0	116.2
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		0.8	0.4	0.0	43.0	34.8	28.8
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		34.7	35.3	23.8	542.1	429.9	349.9
24. Cents/kwh Rate							

TABLE A4-8. RECOVERY OF SUNK COSTS, USEFUL LIFE OF 30 YEARS

1. Capacity Factor
2. BECO Share of
 Generation (MW): 0
3. Retirement Date: 2004

	Base	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Plant-in-service											
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150	0	0	0	0	0	0	0	0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation											
7. Beginning of Year			152.6	187.0	225.7	264.5	303.3	342.1	380.9	419.6	458.4
8. Annual Depreciation			34.4	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8
9. End of Year		152.6	187.0	225.7	264.5	303.3	342.1	380.8	419.6	458.4	497.1
10. Net-Plant (Year-End)		543.5	659.1	620.4	581.6	542.8	504.0	465.3	426.5	387.7	348.9
Other Rate Base Items											
11. Deferred Taxes			-103.7	-112.9	-121.5	-127.9	-143.1	-145.7	-142.7	-138.2	-132.9
12. Materials & Supplies			20	0	0	0	0	0	0	0	0
13. Nuclear Fuel			51	0	0	0	0	0	0	0	0
14. Average Rate Base			551.4	507.5	460.1	414.9	360.9	319.6	283.8	251.5	216.1
14A. BECO Portion			413.6	380.6	345.1	303.7	270.7	239.7	212.9	188.6	162.0
Costs											
15. Return on Rate Base		42.8	39.4	35.7	31.4	28.0	24.8	22.0	19.5	16.8	
16. Income Taxes		20.3	18.6	16.8	14.8	13.3	11.7	10.4	9.2	7.8	
17. Depreciation		25.8	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	
18. O&M Expenses		-2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
19. Insurance/Overhead		-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
20. Local Taxes		7.9	7.4	7.0	6.5	6.0	5.6	5.1	4.7	4.2	
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
23. Annual Cost		92.4	94.5	88.6	81.9	76.4	71.2	66.8	62.5	58.0	

TABLE A4-5: RECOVERY OF SUN COSTS, USEFUL LIFE OF 32 YEARS

1. Capacity Factor:
2. BECO Share of
 Generation (MW): 0
3. Retirement Date: 2004

	Base	1996	1997	1998	1999	2000	2001	2002	2003	2004	[illegible]
Plant-in-service											
4. Beginning of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	
5. Net Additions		0	0	0	0	0	0	0	0	0	
6. End of Year		846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	
Accumulated Depreciation											
7. Beginning of Year		497.1	535.9	574.7	613.5	652.2	691.0	729.8	768.6	807.3	
8. Annual Depreciation		38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	
9. End of Year		535.9	574.7	613.5	652.2	691.0	729.8	768.6	807.3	846.1	
10. Net-Plant (Year-End)		310.2	271.4	232.6	193.9	155.1	116.3	77.5	38.8	0.0	
Other Rate Base Items											
11. Deferred Taxes		-125.7	-121.5	-105.2	-80.3	-59.6	-36.7	25.5	66.3	0	
12. Materials & Supplies		0	0	0	0	0	0	0	0	0	
13. Nuclear Fuel		0	0	0	0	0	0	0	0	0	
14. Average Rate Base		184.5	149.9	127.4	100.6	95.5	79.6	103.0	105.1	0.0	
14A. BECO Portion		138.4	112.4	95.6	75.4	71.6	59.7	77.3	78.8	0.0	
Costs											
15. Return on Rate Base		14.3	11.6	9.9	7.8	7.4	6.2	8.0	8.1	0.1	175.1
16. Income Taxes		6.8	5.5	4.7	3.7	3.5	2.9	3.8	3.9	0.0	83.0
17. Depreciation		29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	233.4
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		3.7	3.3	2.8	2.3	1.9	1.4	0.9	0.5	0.0	37.5
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		53.9	49.5	46.4	42.9	41.9	39.6	41.8	41.6	29.1	529.0

TABLE 33-B: SENSITIVITY OF BCTC COSTS, USEFUL LIFE OF 30 YEARS

1. Capacity Factor
2. BECO Share of
 Generation (MW): 0
3. Retirement Date: 2014

		CNPVRR @	CNPVRR @
	Case	15.00%	20.00%
	----	------	------
Plant-in-service			
4. Beginning of Year			
5. Net Additions			
6. End of Year			
Accumulated Depreciation			
7. Beginning of Year			
8. Annual Depreciation			
9. End of Year			
10. Net-Plant (Year-End)			
Other Rate Base Items			
11. Deferred Taxes			
12. Materials & Supplies			
13. Nuclear Fuel			
14. Average Rate Base			
14A. BECO Portion			
Costs			
15. Return on Rate Base		146.9	124.9
16. Income Taxes		69.1	53.6
17. Depreciation		194.4	157.1
18. O&M Expenses		0.0	0.0
19. Insurance/Overhead		0.0	0.0
20. Local Taxes		31.9	25.3
21. Decommissioning		0.0	0.0
22. Fuel		0.0	0.0
23. Annual Cost		441.3	348.9

TABLE A4-C: RECOVERY OF SCPC COSTS, USEFUL LIFE OF 25 YEARS

1. Capacity Factor
2. BECO Share of
 Generation (GWH : 0
3. Retirement Date: 1997

	Base	1985	1987	1988	1989	1990	1991	1992	1993	1994
Plant-in-service										
4. Beginning of Year			696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
5. Net Additions			150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. End of Year		696.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1	846.1
Accumulated Depreciation										
7. Beginning of Year			152.6	208.8	272.6	336.3	400.0	463.7	527.5	591.2
8. Annual Depreciation			56.2	63.7	63.7	63.7	63.7	63.7	63.7	63.7
9. End of Year		152.6	208.8	272.6	336.3	400.0	463.7	527.5	591.2	654.9
10. Net-Plant (Year-End)		543.5	637.3	573.5	509.8	446.1	382.4	318.6	254.9	191.2
Other Rate Base Items										
11. Deferred Taxes			-103.7	-121.5	-143.1	-145.7	-136.2	-129.5	-114.9	-93.3
12. Materials & Supplies			20	0	0	0	0	0	0	0
13. Nuclear Fuel			51	0	0	0	0	0	0	0
14. Average Rate Base			529.6	452.0	366.7	300.4	246.2	189.1	140.0	97.9
14A. BECO Portion			397.2	339.0	275.0	225.3	184.6	141.8	105.0	73.4
Costs										
15. Return on Rate Base		41.1	35.1	29.4	23.8	19.1	14.7	10.9	7.8	
16. Income Taxes		19.5	16.6	13.5	11.0	9.0	7.0	5.1	3.8	
17. Depreciation		42.2	47.8	47.8	47.8	47.8	47.8	47.8	47.8	
18. O&M Expenses		-3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
19. Insurance/Overhead		-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
20. Local Taxes		7.6	6.9	6.1	5.4	4.6	3.8	3.1	2.3	
21. Decommissioning		15.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
23. Annual Cost		121.4	106.3	95.8	87.5	80.5	73.2	66.9	61.2	

TABLE A4-C: BECO EP' OF FLOW COSTS, USEFUL LIFE OF 25 YEARS

1. Capacity Factor
2. BECO Share of
 Generation (MW): 0
3. Part Start Year: 1997

	Case	1995	1996	1997	CNPVRR @ 10.04%	CNPVRR @ 15.00%	CNPVRR @ 20.00%
Plant-in-service							
4. Beginning of Year		846.1	846.1	846.1			
5. Net Additions		0.0	0.0	0.0			
6. End of Year		846.1	846.1	846.1			
Accumulated Depreciation							
7. Beginning of Year		654.9	718.6	782.4			
8. Annual Depreciation		63.7	63.7	63.7			
9. End of Year		718.6	782.4	846.1			
10. Net-Plant (Year-End)		127.5	63.7	0.0			
Other Rate Base Items							
11. Deferred Taxes		-36.7	25.5	0			
12. Materials & Supplies		0	0	0			
13. Nuclear Fuel		0	0	0			
14. Average Rate Base		90.8	89.2	0.0			
14A. BECO Portion		68.1	66.9	0.0			
Costs							
15. Return on Rate Base		7.0	6.9	0.0	110.2	97.3	86.3
16. Income Taxes		3.3	3.3	0.0	52.2	46.1	40.9
17. Depreciation		47.8	47.8	47.8	299.4	239.9	200.4
18. O&M Expenses		0.0	0.0	0.0	0.0	0.0	0.0
19. Insurance/Overhead		0.0	0.0	0.0	0.0	0.0	0.0
20. Local Taxes		1.5	0.8	0.0	24.5	21.6	19.0
21. Decommissioning		0.0	0.0	0.0	0.0	0.0	0.0
22. Fuel		0.0	0.0	0.0	0.0	0.0	0.0
23. Annual Cost		59.7	58.8	47.8	476.4	404.9	346.5